Victorian EDPR 2021-26 – online public forum

Public forum questions for 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. Would the distributors care to comment on this observation?	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. 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 methodologies for some engagement will need to be adapted.)	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. 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	(a) In the current and forthcoming regulatory period, we are proposing to spend $548.7 million ($2021) on REFCL.

		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?	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 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	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

AusNet Services)			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 peak load at these places in the network?	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.

			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 (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?	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 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?	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

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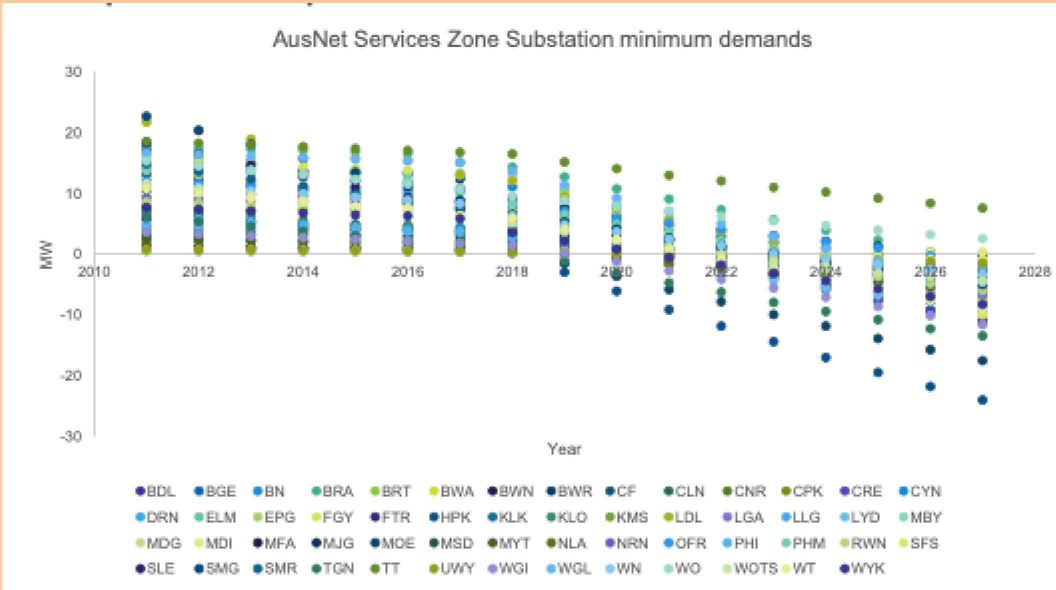

Figure 3 – Estimated power flows at ZSS based on the pre Solar Homes Package Program (base forecast)
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constraints. It is not possible to reduce the voltage set points further in flat settings in our HV voltage regulators without compromising the number 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.
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<td>EUAA (from public forum presentation)</td>
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<td>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)</td>
<td>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</td>
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			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);

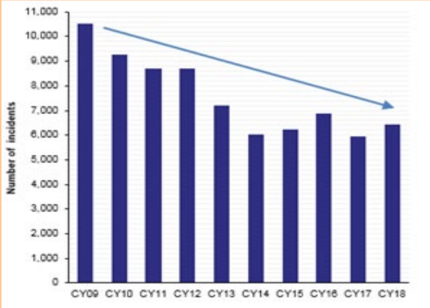
			▪ For this reset, discussions on a one-one basis, noting that we have we have used this approach already, including with the CCP-17 and EUAA/ Brotherhood of St Lawrence; and ▪ Continued customer research and increased grass roots engagement and listening (a reflection of the cultural change that has 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

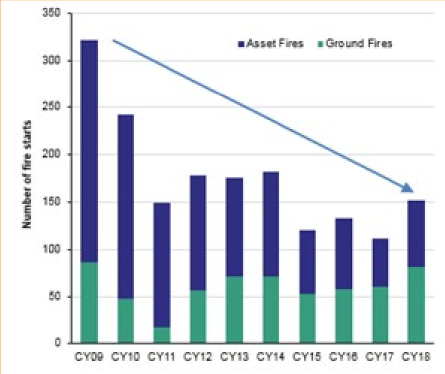
			marginal cost generation. This benefits all customers, including our business customers. Our proposed expenditure will also ensure our customers can export excess energy only where the cost of us carrying out works is economically efficient. That is, we will only invest until such time as our solar, 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.

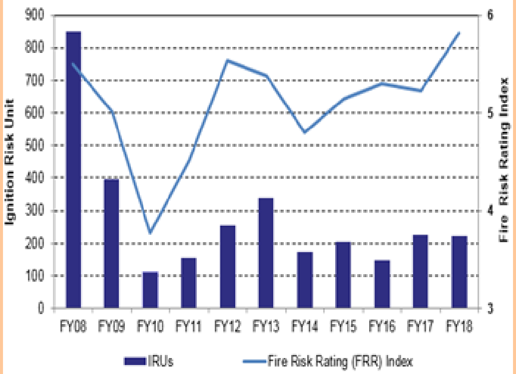
Incidents with fire potential



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) 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.

		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]**?	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.