Victorian EDPR 2021-26 – online public forum

Public forum questions for CitiPower, Powercor and United Energy

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?	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	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.

		scope for greater efficiency of network utilisation without more spending, particularly on capital programs?	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? b) Could the utilities comment on the findings?	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 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

		the business's Demand Management programs for 2021-26, and how that differs from current programs?	management programs, which substitute capital 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

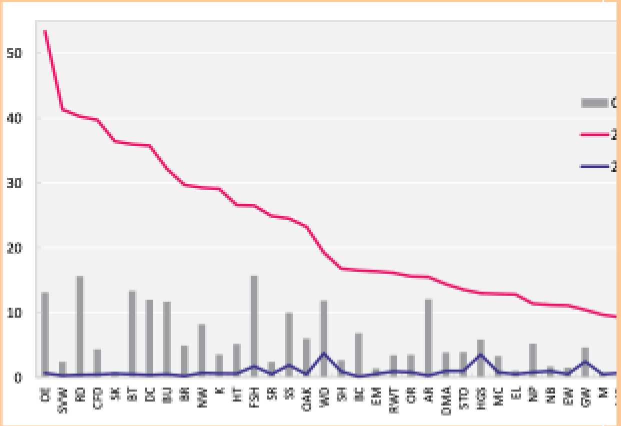
			demand management capabilities further and defer more augmentation in the future.
	Consumer Engagement	Recognising that COVID-19 has dramatically appeared since revenue proposals were lodged, we would like to know what plans the individual businesses have for engagement in a setting where face to face 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 impact on the network. We certainly note the community benefits of the REFCL investment, and do not seek to revisit any cost/benefit	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 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

		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?	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 and United Energy)	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 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 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	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 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

		of the response.	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 hour 	
		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 mange 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

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)

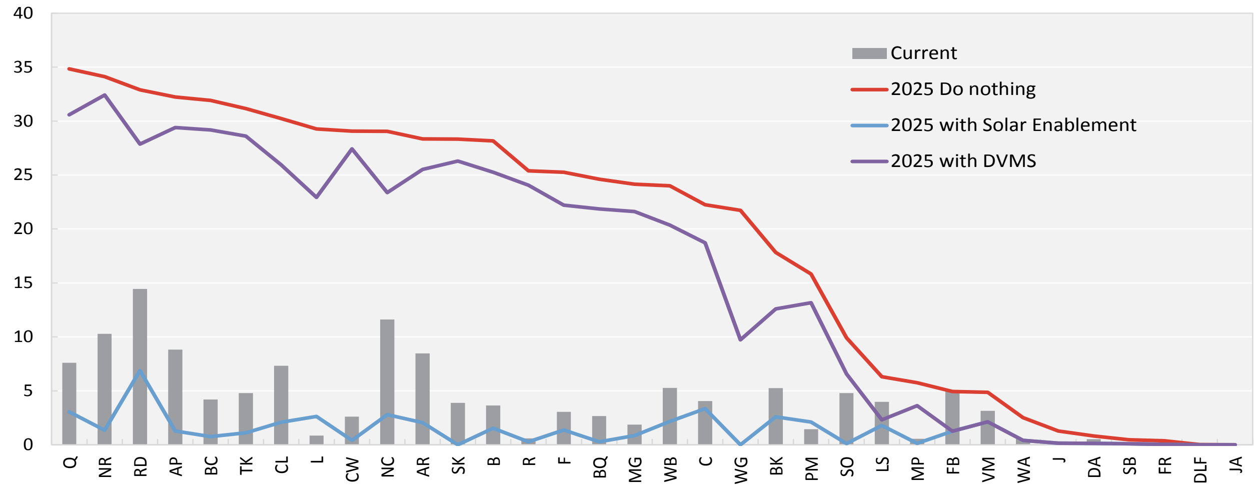


Figure 1 Powercor, percentage of time solar is constrained (showing the impact of DVMS)

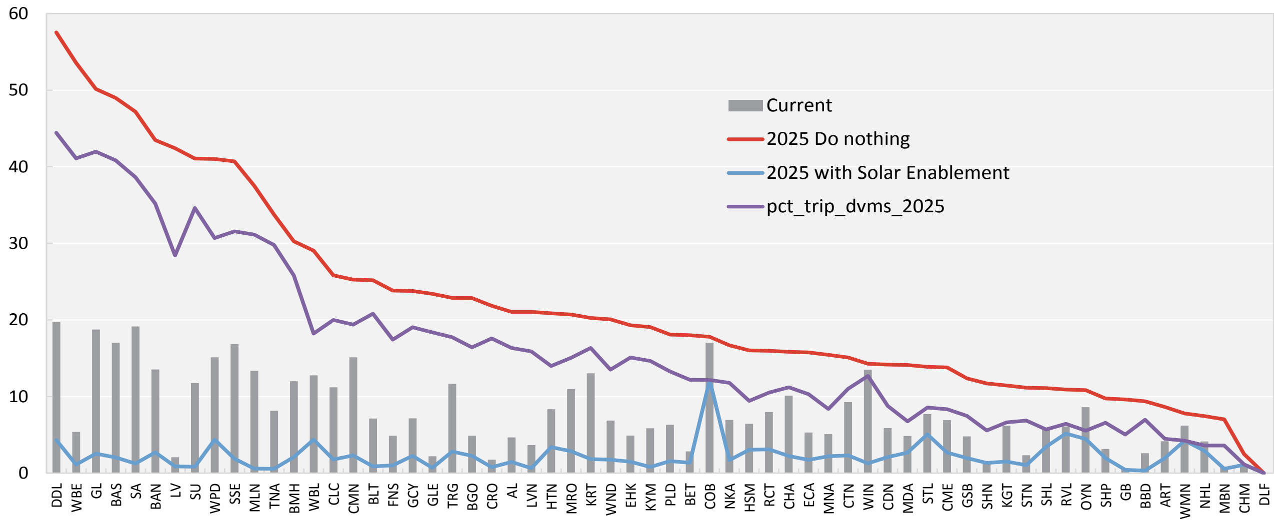


Table 2 Future network comparison

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