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Victorian Electricity Distribution Determinations 2021-26 – regulatory proposals – 31 January 2020

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

We appreciate the opportunity to provide comments on the initial proposals of the Victorian distribution network service providers (DNSPs) for the 2021-26 regulatory period. We currently have over 450,000 electricity customers in Victoria that will be directly impacted by the AER's determinations for these businesses.

The main points raised in the attached submission are:

- there should be more transparency and consistency in the reporting of customer bill impacts arising from network proposals and the AER's decisions
- the price reductions arising from the proposals are largely due to separate regulatory decisions that have been imposed on the DNSPs, and these reductions are in spite of increased spending that is within their control. The DNSPs should be challenged further and in line with pressures across the economy to find cost reductions
- proposals by AusNet in particular to change depreciation schedules should be validated with detailed modelling to ensure they are revenue neutral
- we are supportive of moves to make tariffs more transparent and cost reflective
- there are some aspects in the treatment of distributed energy resources (DER) that warrant closer attention, particularly the value of solar export.

If you would like to discuss this submission, please contact me on [redacted] or [redacted]

Regards

Lawrence Irlam
Industry Regulation Lead

What is the actual bill impact for mass market customers?

The large expenditures and revenues associated with delivering network services are far removed from what the individual customer experiences in the energy market. Most customers are unaware of the periodic assessments of network proposals, even though this is a major determinant of the bills they pay. Customers are, however, acutely aware of retail price changes and most do not distinguish between the different parties in the energy supply chain. The accurate reporting of price changes for network business is becoming critical as retailers may now be penalised where retail prices are found to diverge from underlying costs. As we have seen with recent media reporting of wholesale spot prices, discussion of cost reductions in the supply chain may raise unrealistic expectations around the costs retailers actually face. If expected cost reductions are not delivered, this can cause reputational damage for the entire sector, including the AER in its administration of price regulation.

We noted inconsistencies in how price impacts are reported by DNSPs and by the AER in a submission on Energex's regulatory proposal last year. There are a variety of ways to report price or bill changes. There may be a tendency for NSPs to choose those that present their proposals in the most favourable light. We recommended to the AER that price impacts be reported on a consistent basis.[1]

In considering our earlier submission and concerns, the AER noted that "[w]e consider that our assessment provides the best reflection of the price impacts based on our draft decision."[2]

The following illustrates our concerns again in the case of AusNet, however the same issues of comparability are present to varying degrees across all five proposals now before the AER, and in the AER's issues paper.

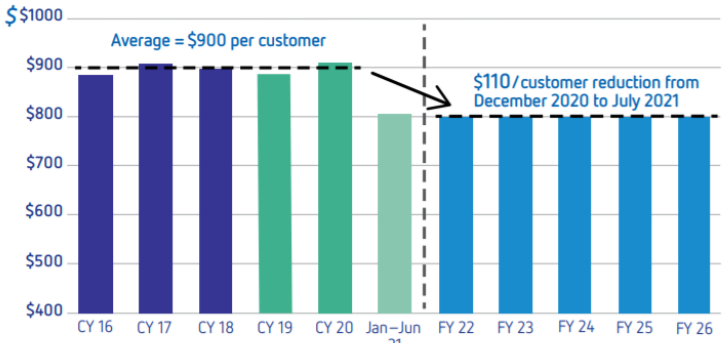
AusNet's proposal overview document presents a headline impact of "prices lower by $110 per customer… This is the reduction in revenue per customer in real $2021 from December 2020 to July 2021."[3] This figure is not a bill or price change that would be experienced by the majority of customers in moving from the current to the forthcoming regulatory period. As illustrated in the chart below, this is the change in total regulated revenue divided by the number of customers, for the prior five years compared to the forthcoming regulatory control period. Furthermore, these values are all expressed in real 2021 dollars. Customers do not transact in real terms, and this conversion to real values tends to overstate the quoted change in average revenues as it inflates historic values while deflating forecasts.

[1] https://www.aer.gov.au/system/files/EnergyAustralia%20-%20Submission%20on%20Energex%27s%20Regulatory%20Proposal%202020-25%20-%203%20June%202019.pdf

[2] AER, *Draft Decision: Energex Distribution Determination 2020 to 2025 - Attachment 1 Annual revenue requirement*, October 2019, p. 1-14.

[3] AusNet Services, *Delivering better outcomes for customers, Overview of our electricity distribution regulatory proposal 20212–26*, January 2020, p. 3.

Figure 3: Proposed reduction in average revenue per customer ($2021)



Source: AusNet Services

AusNet's overview document also states that the "charge" and "prices" for electricity distribution services will be:

- in real terms, $48 or 10 per cent less for a residential customer on average; and $627 or 13 per cent less for a non-residential customer on average
- in nominal terms, $27 or 6 per cent less for a residential customer on average; and $430 or 9 per cent less for a non-residential customer on average.[4]

Data provided in AusNet's indicative bill impact template states that the nominal change in annual bills from 1 July 2021 would be a reduction of $7 for residential customers and $12 for small businesses.[5]

These much lower reductions align with, but still don't reconcile to, the AER's issues paper calculations of a $12 reduction for residential and $17 reduction for small businesses.[6]

Of all these figures, the $110 reduction was reported in in at least one media outlet:

> "By engaging more extensively than ever before with its customers, and working with the Customer Forum, AusNet has reflected their needs and expectations by… Making services more affordable: the **average bill will fall by $110**, or 12 per cent, from December 2020 to July 2021…"[7] [emphasis added]

In this case, the $110 reduction in real average revenue per customer has thus been interpreted as a nominal bill impact, even though it obviously overstates the expected change in residential and small business bills at the commencement of the forthcoming regulatory period.

Also concerning is that the figures reported for each DNSP, including by the AER, do not seem to reconcile across the mix of real and nominal values, average revenue and imputed bill changes. Adding to confusion for the forthcoming regulatory period is the revenue determination expected to apply for the 6 months to 30 June 2021.

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[4] AusNet, pp. 19-20.
[5] AusNet Service - Workbook 07 - Bill Impacts (2022-26) - 31 January 2020.xlsm, tab 7.6.
[6] AER, *Issues Paper: Victorian electricity distribution determination 2021 to 2026*, April 2020, table 18.
[7] https://utilitymagazine.com.au/customers-get-a-say-in-ausnet-services-network-plans/

Published bill impacts - residential customers

	"headline" impact from Proposal overviews	Indicative bill impact templates (nominal)	AER issues paper (nominal)
Ausnet	Reduction of $110 per customer, real $2021, from December 2020 to July 2021 $27 nominal reduction for a residential customer on average	$30 reduction for 2021:H1 $7 reduction in 2021-22 average increases of $24 per year thereafter	$12 reduction in 2021-22 average increases of $26 per year thereafter
United	Reduction of annual distribution and metering charges on average over the five years by $54 for residential customers	$66 reduction for 2021:H1 $30 reduction in 2021-22 average increases of $6 per year thereafter	$42 reduction in 2021-22 average increases of $6 per year thereafter
Citipower	Reduction of annual distribution and metering charges on average over the five years by $38 for residential customers	$46 reduction for 2021:H1 $10 reduction in 2021-22 average increases of $6 per year thereafter	$23 reduction in 2021-22 average increases of $5 per year thereafter
Powercor	Reduction of annual distribution and metering charges on average over the five years by $24 for residential customers	$42 reduction for 2021:H1 $3 increase in 2021-22 average increases of $5 per year thereafter	$4 reduction in 2021-22 average increases of $5 per year thereafter
Jemena	Over the 2021-26 period and excluding the impact of inflation, a typical residential customer will save approximately $320 (14 per cent) when compared to their bills within the current regulatory period.	$53 reduction for 2021:H1 $4 increase in 2021-22 average increases of $6 per year thereafter	$34 reduction in 2021-22 average increases of $6 per year thereafter

Sources: DNSP proposals, indicative bill impact templates, AER issues paper.

We again recommend that the AER develop and enforce requirements on DNSPs to present accurate price and bill impacts that approximate what customers might actually pay. The AER's reporting should be on the same basis. DNSPs are already required to submit indicative customer bill impacts with their regulatory proposals. The values in these templates are derived from retail and network bills however do not appear to be used by the AER or DNSPs. There is scope to improve these templates by aligning with reference pricing and consumption benchmarks now used in advertising at the retail level under the Default Market Offer and the Victorian Default Offer (VDO). For Victorian DNSPs, the VDO also is based on specific network tariffs that service the majority of mass market customers in each distribution zone, and these should be adopted. We note that some DNSPs already appear to have used the VDO maximum bill amounts in their indicative bill impact calculations.

The businesses should be challenged to contain controllable costs

As pointed out in the AER's issues paper and discussed recently at the AER's public forum, the expected initial price reductions arising from all five regulatory proposals are mostly attributable to preceding AER rulings on the rate of return and on benchmark tax allowances. While these have significant revenue impacts for the DNSPs, they are basically outside of their control. The DNSPs would be proposing material price increases in the absence of these factors and should be robustly challenged on factors that are within their control.

The main factors contributing to price changes, aside from the rate of return and tax, appear to be:

- increases in opex relative to current period allowances for Jemena, CitiPower, Powercor, with decreases for AusNet and Jemena
- revenue increments for all DNSPs due to rewards paid out via incentive carry-over mechanisms
- reductions in regulatory asset base (RAB) values from current period forecasts, owing to capex underspends in the current period
- large increases due to depreciation in the cases of AusNet and United Energy.

We question whether the forced reductions to the DNSPs' cost of capital and benchmark tax allowances have been offset by avoidable increases in other areas of the proposals, while still delivering an overall price reduction that might appear acceptable to customers and the AER. As discussed above, it is difficult to ascertain the true 'headline' proposed price change. For all the DNSPs the initial proposed price decrease is followed by increases for most of the forthcoming period.

The DNSPs' proposals refer to commitments to achieve further efficiency gains, relative to 'unconstrained' forecasts or those presented to customers during pre-lodgement discussions. These are to be encouraged. Some examples of this in the DNSPs' main proposal documents include:

- a 27 per cent reduction in major project repex from preliminary forecasts discussed with its Customer Forum, as well as a doubling of the AER's productivity adjustment to over 1 per cent (AusNet, Part I and II, pp. 17-20)
- a "transformation program", completed in 2019, involving rearranging of field staff to maximise savings by leveraging scale, implementing streamlined processes and systems to reduce manual process handling, and introducing other resource-saving initiatives (Jemena, p. 62)
- generally noting their positions as efficiency frontier networks and applying the AER's 0.5 per cent productivity adjustment, with some technology investments expected to contribute towards these gains (Citipower, p. 113-5, Powercor pp. 132-4, United pp. 160-2).

We also appreciate the significant efforts of each DNSP to engage with customers in preparing their proposals. We have not been part of discussions with customer representatives, nor have we examined how these discussions have affected the proposals in detail. We fully support improvements to the regulatory framework that put customers at the centre of the arrangements, as well as instances where customers genuinely understand and accept initiatives that deliver value for them in terms of lower prices and improved outcomes over the long term. At the same time, we would also have concerns where the DNSPs have presented cost drivers to customers and sought their 'buy-in' without proper scrutiny of cumulative price impacts, including of alternative options where costs or benefits are spread across customer segments differently. As mentioned below, notions of 'all customers pay' in the case of DER enablement may be an example of this. The AER may wish to explore the extent to which customer bill impacts in the presence and absence specific spending initiatives (or indeed for the entirety of the proposals, as per our concerns above) have been accurately presented to customer groups in pre-lodgement discussions.

The framework embodied in the NER, for which the AER is ultimately accountable, is intended to replicate the pressure of competitive markets where businesses are prevented from freely passing on a tally of all their likely and actual spending onto customers. At the same time, this framework tends to result in regulated entities presenting detailed justifications of their own cost drivers and associated spending for the AER's assessment, with the expectation that the AER will reject some of these while still leaving an overly conservative set of allowances. Such conservatism was acknowledged recently by the AER as well as thresholds for considering whether businesses are materially inefficient.[8] Within these bounds of inaccuracy, materiality and judgement, the AER should form an overall view on whether the proposals reflect a genuinely challenging combination of expenditure budgets and service output targets. The same should be done whenever the AER determines its own substitute values. Perhaps because of NER requirements, the AER has tended to present an unrealistically firm view of the efficiency of its substitute allowances. This appears to have led to some DNSPs to present instances of underspending as necessarily efficient without reference to any ex post analysis of their spending, or of the AER's allowances.[9]

The AER's Consumer Challenge Panel 17 has questioned whether we should still observe instances of large underspends by the Victorian DNSPs.[10] These DNSPs have been subject to incentive regulation for over 20 years and are (mostly) regarded as highly efficient relative to their Australian peers. This is supported by comments in the proposals by some of the DNSPs who regard themselves as being at the efficiency frontier. Arguably they should be proposing (or be subject to) more aggressive cost reductions in line with their own spending trends, and be provided with higher-powered incentives for outperforming these, where they do genuinely set frontier performance for the benefit of consumers across the NEM.

In addition to this, the ongoing downturn associated with COVID-19 should provide new pressures to achieve cost reductions, as are being felt in competitive sectors of the economy. In the energy sector, affordability is still a key concern for our customers. Retail margins are now at historic lows[11] and wholesale prices are below those required

[8] AER, *Victorian EDPR 2021-26 – collated online public forum questions and responses*, May 2020, p. 2.

[9] For example: Jemena, *2021-26 Regulatory proposal – overview*, pp. 62, 64.

[10] CCP17, *AER Public Forum presentation and response to issues paper*, 22 April 2020, slide 49.

[11] Specifically, EBITDA margins (that is, 'gross' and not 'net' margins) were on average 4 per cent of the total residential retail bill in 2018-19, and were trending downwards, before the introduction of the DMO, VDO and now 'divestment' legislation. See ACCC, *Inquiry into the National Electricity Market - November 2019 Report*, 29 November 2019, pp. 39-42.

to support investment in much needed firm replacement capacity. Recognising that the AER's 2018 Rate of Return instrument resulted in large reductions in the WACC, equity returns approaching 5 per cent for these DNSPs (and increasing, with likely outperformance of expenditure allowances) are enviable. The expected global economic downturn should also depress cost inputs forming part of the DNSPs' expenditure proposals, and we expect to see this addressed as revised proposals are lodged.

Capex and opex proposals appear to be high with respect to trends

The AER's issues paper usefully plots time series of actual expenditures versus allowances back to 2009-10. As per the table below, it notes that in some instances, proposed expenditures are significantly below current period allowances, particularly AusNet and for Jemena's capex. In considering this and other information, the AER states it may conduct a less extensive analysis of AusNet's expenditure forecasts relative to other DNSP proposals.[12]

Table 5 Comparison of the regulatory proposals (in real terms)

	Customer service	Revenue	Opex	Capex	RAB per customer
AusNet	↑ Substantial improvement	↓ 5.6%	↓ 8.8%	↓ 27.5%	↓ 6.3%
CitiPower	↑ Some improvement	↓ 4.5%	↑ 13.7%	↓ 6.7%	↑ 5.0%
Jemena	↑ Some improvement	↓ 6.2%	↑ 11.8%	↓ 18.7%	↑ 4.2%
Powercor	↑ Some improvement	↑ 1.0%	↑ 11.9%	↑ 6.4%	↑ 7.4%
United Energy	↑ Some improvement	↓ 5.8%	↓ 4.9%	↑ 19.2%	↑ 7.4%

Note: Revenue, capex and opex comparisons are relative to our previous determination. Change in RAB per customer reflects the difference between the opening (1 July 2021) and closing (30 June 2026) RABs. Detailed change in customer service is set out in section 2.2.

Source: AER issues paper.

The AER should conduct further trend analysis with respect to the DNSPs' proposed values for the current regulatory control period. This may be more useful to undertake for particular recurrent categories of expenditure as presented at the AER's recent forum.[13] This analysis can highlight instances of persistent over- or under-estimation, leading to further investigation of the credibility of forecasting methods, how these have improved over time as well as areas where DNSPs, the AER and customers must deal

[12] AER Issues paper, pp. 29-30.

[13] Brotherhood of St Laurence et al, *2021-2026 Victorian EDPR- Presentation to AER Public Forum from community organisations,* April 2020. See analysis of repex, non-network and IT spending.

with genuine forecasting risk. Where such risk is unavoidable for the forthcoming regulatory control period, the AER could weaken incentives placed on DNSPs or revisit the extent of conservatism in parts of its forecasts. Overall, we would encourage any measures that minimise the prospect of windfall gains while still pushing DNSPs to drive further efficiencies in their businesses.

The AER has stated it also considered trends against actual expenditure for the current period. Comparisons on this basis naturally reveal different outcomes than presented in the table above. The proposed opex allowances of all the DNSPs are above recent trends in actual expenditures, ranging from an 8.4 per cent increase in the case of AusNet and up to 40 per cent for Citipower.[14] We question whether fielding and potentially allowing numerous opex step changes reflects poorly on the integrity of the AER's revealed cost framework, and whether it should take a harder line to preserve this.

In terms of capex, AusNet's proposal is still a large reduction (22 per cent) when compared to actual and estimated expenditure for the current period. Spending on REFCL is the main driver for this reduction, with AusNet identifying that gross capex for the forthcoming period would be 5.2 per cent lower than the current period where REFCL capex is ignored.[15] Jemena's proposed capex is 18.7 per cent less than its current period allowance but is 6 per cent higher than actual and estimated expenditure for the current period.[16] High level trends examined by Brotherhood of St Laurence and others indicate that the Victorian DNSPs have, with few exceptions, persistently overbid and underspent repex allowances.[17] As noted above, this may suggest bias in the DNSPs' and the AER's forecasting methods rather than efficiency gains that should generate rewards under incentive frameworks.

The proposals by Citipower, Powercor and United Energy reflect a combination of material capex underspends in the current period, with efficiency carryovers as a result, and higher proposed capex allowances for the forthcoming period. This combination should be closely scrutinised wherever it arises as it may reveal gaming of the AER's capex incentive regime, for example, via inefficient capex deferral. Adjustments to incentive payments (noting some have been proposed by the DNSPs) to correct for this should be made in accordance with the AER's Capital Expenditure Sharing Scheme guideline.

As we have suggested previously, the AER should consider the use of different 'outputs' metrics to examine the efficiency of historic expenditures, in combination with higher level indices of factor productivity. This includes physical asset data associated with capex and measures of service underpinning opex that are already being collected through the AER's Regulatory Information Notices. These metrics would provide an additional layer of scrutiny of expenditures and validate incentive payments against the items on which DNSPs actually spend money. The AER's forthcoming measures of network profitability[18] will also be an important measure of the actual spending relative to allowances for each regulated network.

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[14] AER issues paper, section 4.7
[15] Forum answers, p. 13.
[16] AER issues paper, section 4.8.5.
[17] Brotherhood of St Laurence et al, p. 18.
[18] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses/decision

The AER should confirm that changes to depreciation are revenue neutral

AusNet's proposal involves separating out $209 million worth of assets, attributed to protection relays and remote terminal units, from asset classes that currently have 45 and 50 year standard lives. AusNet proposes to depreciate these in new asset class with a remaining life of 5.3 years. This results in an increase in proposed revenues of around $40 million, or by 6 per cent each year.

AusNet notes that, prior to 2016, capex attributed to these assets has included in the 'sub-transmission' and 'distribution system' asset classes and it has not previously proposed any transfers or accelerated depreciation of these assets.[19] Asset classes for SCADA/network control and non-network IT (with standard lives of 10 and 5 years) were introduced in the AER's determination for 2016-20.

AusNet's overall justification for this change appears to be to comply with NER clause 6.5.5(b)(1), which requires that depreciation schedules used by the DNSP reflect the economic lives of the assets (or asset categories).

Our concern with this and similar proposals relating to changes to depreciation schedules are as follows:

- We question whether the AER is and should be policing the requirements under clause 6.5.5(b)(1) when examining proposed depreciation schedules. On the basis of AusNet's estimates, protection relays and remote terminal units currently make up around 4 per cent of its RAB value and are not immaterial. All the Victorian DNSPs have a limited number of asset classes compared to DNSPs in other jurisdictions and we wonder whether there are still large amounts of short-lived assets sitting within the larger classes of 'distribution system' and 'sub-transmission' assets. The category of 'non-network – other' also clearly holds assets with materially different economic lives, as illustrated by Jemena's proposal to reduce the standard life from 24.2 to 5 years, as a consequence of moving building assets to a separate asset class. These changes should have been identified in proposals to the AER in prior reviews.

- Noting AusNet's modelling shows no net change in its closing RAB value as at June 2021, we have some doubts that proposed changes in asset classifications, remaining and standard lives are revenue neutral for DNSPs and customers. The intricacies of the AER's roll-forward model and Post-tax revenue model, including the treatment of capex, inflation and depreciation under incentive mechanisms, need to be closely examined to check if this is the case. The AER should confirm whether it has conducted such a modelling exercise in the case of AusNet's proposal given the large values at stake.

- Even if these changes are proven to be revenue neutral, the NER requirements are written on the presumption that asset lives and values are reconcilable to the physical stock of assets and the cost of their individual installation. The need for AusNet to estimate asset values involved in its proposed change, as well as notional valuation methods that were used to derive the RAB values in NER Schedule 6.2, illustrate the false sense of accuracy associated with the requirement in clause 6.5.5(b)(1). Related to this, clause 6.5.5(b)(2) appears to

[19] AusNet, Regulatory Proposal Part III, p. 198.

require assets to be valued as at the time they were first included in the RAB. This may preclude use of current unit replacement cost estimates, deflated to 1997 dollars, as proposed by AusNet.[20]

Arguably DNSPs should have discretion to depreciate assets over a time of their choosing, provided this is revenue neutral. The requirements of NER clause 6.5.5(b)(2) embody this to some extent by requiring the value of assets to be written off once only.

Decisions about depreciation should reflect commercial factors including cash-flow timing, trends in capex and asset renewal and associated price profiles across multiple regulatory periods. These issues are best discussed with customers and can coincide with expected changes in other costs in the supply chain, as well as the introduction of new tariff structures or other regulatory interventions that affect prices. These factors may still have merit in AusNet's case, noting that the associated 4 per cent increase in its revenues would be far more concerning to customers if not for expected reductions from a lower return on capital and benchmark tax allowances.

As an aside, the reduction in the regulated rate of return may have affected incentives on DNSPs to depreciate assets faster and reallocate expenditures in order to maintain revenue adequacy. Jemena's proposed reallocation of overheads from capex to opex and similar moves by Citipower, Powercor and United to also expense items[21] may illustrate this point, although changes in cost allocation at the time of price resets have not been uncommon in the past.

We encourage more transparency in network pricing and tariff reform

Sales volumes and associated price paths over the forthcoming regulatory control period may arise as a result of COVID-19, with different impacts across customer classes. We will continue to engage with the AER over the course of its assessment as these impacts become clearer, particularly given the need to change network price changes on 1 January 2021 and again six months later.

These impacts aside, we note some instances of DNSPs proposing decreases to network charges on 1 January 2020 with increases from July 2021. Citipower has already identified that such an outcome in its case, involving a proposed increase and then decrease in prices of 15 per cent, would be unlikely in the interests of consumers.[22]

As it relates to transmission use of system (TUOS) charges, Victorian network prices continue to be artificially inflated by the presence of easement land tax levied on AusNet's transmission business. This should be made more transparent in the AER's determinations in terms of its contribution to customer network bills. In recommending that these and other jurisdictional taxes be collected via other means, the ACCC calculated that Victoria's easement land tax contributes $17 per year to residential electricity bills.[23] As the AER would be aware, larger customers connected at higher voltages pay a higher proportion of TUOS in their total bills and transparency of these cost drivers is vital in communicating price changes to our customers.

[20] AusNet, Regulatory Proposal Part III, p. 201.
[21] AER Issues paper, pp. 40-42.
[22] Citipower, *CP APP07 - Transition period 2021*, January 2020, p. 10.
[23] ACCC, *Restoring electricity affordability and Australia's competitive advantage - Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 196.

As it relates to the transparency of this tax, the AER's communication of the reasons for network price changes in Victoria from 1 January 2020 was unsatisfactory:

> Increasing transmission charges in Victoria - representing up to 81 per cent of the price increase - have fed into these 2020 prices.
>
> Some of the reasons for this are rising Victorian land taxes and more power travelling long distances from interstate, which increases costs, have contributed to the rise.[24]

As was reported in media and in feedback from our customers, changes to easement land tax were regarded as the primary contributor to price changes in spite of the change in land tax pass through representing a small amount of annual revenue requirements from 2019 to 2020. Our examination of the DNSPs' pricing proposal data suggests that the pass through of TUOS under-recoveries was instead the major contributing factor to price increases from 1 January 2020. Under-recoveries of distribution revenues were also a contributing factor for some DNSPs.

On tariff reform, we have separately engaged with the Victorian DNSPs in the development of their pricing proposals. The AER's issues paper states that network tariff reform is intended to lead to retailers reforming their retail offers, and lists three broad categories of "new retail offers" which might be passed onto end use customers:

- "Insurance style" — the retailer faces cost reflective network price signals but shields the end customer from this price volatility, for example, by offering the end customer a retail offer with a fixed daily charge and flat kWh energy charge.
- "Pass through" — the network tariff structure is reflected in the retail tariff structure. For example, time-of-use retail rates.
- "Prices for devices" — the retailer manages an end use customer's smart devices to respond to cost reflective network price signals in the background, while keeping simple the retail tariff structure the end use customer actually "sees".[25]

These and related tariff design issues for retailers have been discussed with the AER previously. Retailers will ultimately manage pricing arrangements for their customers as they see fit. However "insurance style" pricing arrangements and other innovative designs where retailers take on additional risk may be less attractive in the presence of the VDO, and regulatory-imposed preferences for simple and stable pricing.[26] New pressures on retailers under the Prohibiting Energy Market Misconduct Act could also entrench "pass through" arrangements, as network costs can be identified in a more transparent manner for price monitoring purposes.

We are also participating in a broader consultation process as part of the Distributed Energy Integration Program. As an outcome of this consultation, we understand the AEMC may soon issue a rule change relating to access and pricing, and expect to engage directly with the AER to the extent it affects pricing and DER integration in the Victorian DNSP determinations. Part of this may be to invest more effort in communicating the

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[24] https://www.aer.gov.au/news-release/aer-approves-victorian-electricity-network-charges-for-2020
[25] AER Issues paper, p. 19.
[26] For example, the ESC's package of changes under its 'Ensuring Fair Contracts' decision involve a range of pricing restrictions including allowing prices to increase only at the time of network price changes.

issues created by growing PV penetration for network and wholesale operation. Recent suggestions by AEMO to ensure solar installations adhere to technical standards, including remote capabilities, were met with negative reaction from solar customers.[27] We expect issues around cost reflectivity, removal of cross subsidies and the drivers for declining feed-in tariffs (FiTs) to become more mainstream in the coming months as further rule changes are publicised.

Aside from these general comments, we support Powercor's proposed changes to its sub-transmission tariff by measuring kVA for its demand charge component from 8am and 8pm on workdays only. The current tariff involves an 'anytime' maximum demand charge, resulting in customers potentially paying more at times when their usage does not contribute to short-term constraints or longer-term drivers for capacity expansion. We also support the proposed narrowing of the peak energy component of this tariff to the same time window. As the operator of the Gannawarra Energy Storage System, the proposed tariff will provide us an appropriate incentive to store energy during off-peak times and discharge at peak times, which promotes efficiency in network service operation as well as wholesale market operation. The AER should be mindful of the rising prevalence of battery installations connected directly to distribution networks when considering network tariff structures.

DER integration proposals tend to overstate the value of solar export

The challenges posed by increasing rates of solar PV and battery penetration in distribution networks are well documented. The measures proposed by the Victorian DNSPs do not appear to involve significant expenditures in the context of their overall spending proposals. However, there may be some scope in standardising approaches in their economic analysis and in dealing with the uncertainties in the rate of DER uptake.

At a high level, we recommend the AER focus on the following when examining the DNSPs' proposals:

- the implicit or explicit pricing and access models – how DNSPs have determined export capacities being offered to customers, whether these are firm or dynamic, and the actual price impacts for different customer segments relative to the benefits they will receive

- how the DNSPs have they valued curtailment or energy export. We note that work is ongoing to determine a value of solar export under the 'VaDER' study which might provide some consistency across the AER's assessment. The likelihood of constraints and curtailment in counterfactual cases may also differ across each network, for example, in relation to PV installations in new versus existing residential developments with different load density or asset redundancy

- Customer preferences and government policies that drive DER uptake may include values attributable to carbon abatement, however such benefits are not recognised under the NER. In Victoria, the ESC's minimum FiT includes a 2.5¢/kWh value representing the social cost of carbon, and this should be recognised wherever this minimum FIT amount is used in quantitative analysis.

[27] https://www.abc.net.au/7.30/energy-regulator-could-force-you-to-switch-off/12269258

Furthermore, we consider that the ESC's minimum FiT materially overstates the value of solar in terms of avoided wholesale energy costs for retailers.

- the DNSPs should be focussed on least regret options given uncertainties in different service delivery models being discussed and the wide range on DER take-up rates

- similarly, DNSPs' actions should allow their networks and customers to be open to third party providers, with careful consideration of the role of the DNSPs' related parties.

In addition to these observations, have examined the following DER-related business cases:

- Citipower, Powercor and United Energy's 'Solar Enablement Plan'

    - This Plan is based on an 'all customers pay' approach on the presumption that all customers benefit. While there are different views on this topic, the AER should validate how the DNSPs arrived at this decision in light of efficiency in pricing as well as direct customer input. Specifically, 65 per cent of customers and stakeholders, including those representing financially vulnerable customers, preferred some form of direct cost recovery from solar customers.[28] Alternative methods of cost recovery seem likely to materially alter the DNSPs' approach, including enabling 5 kVA exports for the large majority of customers.

    - The Plan notes that modelling is undertaken assuming that new customers export a maximum of 3.1kVA (in line with existing customers on average) ramping up to 5kVA in 2025.[29] It is not clear how sensitive the business case is to this assumption and given uncertainties arising from COVID-19 impacts and other sources, this may be worth investigating further.

    - This Plan also includes carbon abatement as one of the benefits in its business case, on the basis that this will ensure solar uptake in accordance with the Victorian Government's Solar Homes program. While from a standard economic viewpoint including carbon reduction benefits is a valid approach, we question whether this is consistent with NER requirements and the AER should examine how this affects the DNSPs' business case.

- Jemena's 'Future Grid' program

    - Jemena adopts the ESC's single rate minimum FiT in valuing curtailed solar exports, which will likely overstate their "true" value, particularly over long time horizons with higher rates of PV penetration behind the meter as well as at grid scale. Jemena's use of a 7¢/kWh FiT as a lower bound sensitivity excludes the social cost of carbon[30], which has merit, but in our view is likely to still overstate the energy only value of PV exports as at today. We note that Jacobs as part of proposals for Citipower,

[28] See for example, United Energy, *Enabling residential rooftop solar- UE BUS06 - Solar enablement – Jan 2020 – Public*, p. 19.
[29] Citipower, *Enabling residential rooftop solar- CP BUS 6.02 Solar Enablement Jan2020 – Public*, p. 32.
[30] Jemena Electricity Networks (Vic) Ltd, *Attachment 05-04 Future Grid investment proposal*, 31 January 2020, p. 20.

Powercor and United Energy determined a value of 4.7¢/kWh for Victoria, which still includes a carbon reduction benefit, while Houston Kemp on behalf of SAPN adopted a value of 5¢/kWh for South Australia.

- Jemena's approach also appears to randomly assign solar installations across its distribution substations which is likely to be an unbiased approach, however locational patterns in the likely rates of penetration and constraints across the network could be inferred from historic information. This or other methods may have been reflected in the 1000 scenarios used in this assignment process but is not clear from Jemena's proposal.[31]

- AusNet's 'Voltage Compliance' and 'Hosting Capacity for DER' programs

    - Like Jemena, AusNet has used the ESC's minimum FiT to value energy exports. AusNet notes that it obtained advice from Frontier Economics in support of this value. Unsurprisingly, Frontier's report for AusNet endorsed its own FiT calculation for the ESC, which was prepared on the basis of projected market conditions and costs for 2020-21. Frontier acknowledge that AusNet's benefits will be calculated beyond a single year however still supports using of its FiT value "in the absence of detailed wholesale market modelling of expected demand and supply conditions in the NEM, which is complex and time-consuming".[32] As with Jemena, this value has been used by AusNet to value exports over a very long time horizon (up to 45 years[33]), where PV as a proportion of the total energy mix will be much greater, with lower daytime spot prices as a result.

    - Frontier also supports recognition of a social cost of carbon, embedded in the ESC's FiT, as a market benefit under the Regulatory Investment Test for Distribution, on the basis of the NER clause 5.17.1(c)(4).[34] This clause arguably allows the AER to identify environmental impacts to be recognised under other classes of benefits, but to our knowledge it has not done so.

    - AusNet's supporting documents, namely its 'Program Brief Distributed Energy Resources'[35] and 'Steady state voltage compliance' document contains considerable commercial-in-confidence redactions, making it virtually impossible to understand AusNet's business case. Values redacted include PV penetration rates, FiT values, costs and benefits, which have all been disclosed by other DNSPs and do not appear to be confidential. This raises broader issues with AusNet's disclosure of information and suggests it is unwilling to expose its proposal to public scrutiny. We recommend the AER discount these documents and other instances of unnecessary redactions in considering AusNet's regulatory proposal.

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[31] ibid., p. 11.
[32] Frontier Economics, *Value of relieving constraints on solar exports – a report for AusNet Services*, 16 October 2019, p. 13.
[33] AusNet Services, *Steady State Voltage Compliance AMS – Electricity Distribution Network*, 29 November 2019, p. 38.
[34] Frontier Economics, p. 2.
[35] AusNet Services, *Technology program Integration of Distributed Energy Resources – PUBLIC*, 19 November 2019.

The AER should consider developing some associated measures of the costs of DER integration versus the expected benefits that can also feed into the policy discussion, which is broader than the DNSPs' pricing determinations. For example:

- costs and measures of LV "visibility"
- benefits related to DER enablement such as better identification and faster rectification of faults
- improvements in network utilisation, including via changes to consumption and demand profiles
- expected volumes of PV curtailment in the presence and absence of programs
- expecting timing of costs and benefits relative to the rate of DER roll-out.

The AER may find some value in examining the analysis conducted on behalf of Energy Networks Australia (ENA) under its OpEN networks program[36], for example:

- uncertainties in the rate of DER uptake have a material impact on the business case for DER investment. The proposals currently before the AER reflect different rates and scenarios (which should be checked for consistency with other inputs in their proposals such as maximum demand and energy sales)
- the ENA may be willing to share data that was provided for this by individual DNSPs to understand how current spending proposals relate to different models of system operation over the longer term
- the benefits arising due to reduced network augmentation due to reduced demand appear much larger than those associated with curtailment, and this may correspond to the business cases presented to the AER.

We also support the ENA's suggestion that ring-fencing arrangements be reviewed as a potential enabler of DER. To address concerns about networks 'crowding out' market participants, the ENA suggests that networks be allowed to invest in providing access to DER up to a certain threshold. We do not necessarily agree, and consider that these concerns may be better (or additionally) addressed by examining the role of NSPs' related parties in procurement and service delivery.

Finally, and separate to the consideration of regulatory proposals, we support United Energy providing information on its low voltage network with its Distribution Annual Planning Reports. Typically these reports only examine the distribution substation level and above. We understand that DNSPs retain a significant amount of data below this level that is worth releasing to the market. This would allow retailers and other parties to identify emerging opportunities to deliver value for customers, including innovative means to avoid constraints and deliver additional capacity when needed.

[36] https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/open-energy-networks-project-energy-networks-australia-position-paper/