Photo: 66kV switch, Powercor, 1997

Consumer
Challenge
Panel

Victorian Electricity Distribution Businesses
2021 - 26 Revenue Determinations

AER Public Forum presentation and response to issues paper

22 April 2020

CCP17
Robyn Robinson
David Prins
Mark Henley
Mike Swanston

Context

- The information presented in this document is based on preliminary views by CCP17
- These slides have been prepared with the intention to be part of a discussion in a forum rather than a formal report or advice.
- We acknowledge that all estimates are likely to be reviewed to consider the impact of the changed economic and social environment that may exist during and after the global pandemic.

In this document, we use the abbreviation ‘CPU’ to refer to the three companies with some common ownership: CitiPower, Powercor and United Energy

Our role as a Consumer Challenge Panel (CCP)

We advise the AER on:

1. Whether the network businesses' proposals are in the long-term interests of consumers, *and*
2. The effectiveness of network businesses' engagement activities with their customers –
   i. the issues on which each business engaged with its customers and stakeholders,
   ii. how this engagement has influenced the revenue proposal,
   iii. whether consumers agree with the revenue proposal, and
   iv. is there a process for ongoing review of CE/continuous improvement

We consider this role in the context of the National Electricity Objective (NEO)

Emphasis on "challenge" to both the network and the AER

Aim of getting to a proposal that is "capable of acceptance"

The AER is guided by the NEO

National Energy Objective (NEO):

> *“to promote efficient **investment** in, and efficient **operation** and use of, energy services for the **long term interests of consumers** of energy with respect to **price, quality, safety, reliability and security** of supply of energy.”*

Therefore, we consider:

- How prudent and efficient is proposed capex/opex expenditure?
- How will costs be allocated to different customer groups?
- How does the proposal reflect the changing electricity market and long-term issues?

Not all components of the revenue reset are part of this current process

The 'in scope' capex/opex items account for ~ 35-40% of a DNSP's proposed revenue

To be determined as part of this regulatory process	Already established through binding guidelines and decisions
Proposed capex in period / Regulated Asset Base (RAB)	Rate of return – AER binding guideline in December 2018
Proposed opex in period	Opex productivity – AER decision March 2019 for 0.5%/yr
Forecasting methodology and findings	Taxation allowance – AER decision in December 2018
Application of incentive schemes	Form of incentive schemes
Application of regulatory depreciation	Regulatory depreciation methodology
Tariff Structure Statement	
Consumer engagement is taken into account	

CCP involvement to date

Consumer Challenge Panel sub-panel 17 (CCP17) was established by the AER in November 2017 to provide advice on the 2021-26 Victorian Electricity Distribution Revenue Determination

During 2018 and 2019, CCP17:

- observed multiple consumer engagement events conducted by each of the businesses
- met 5 times with each of the businesses to discuss development of regulatory proposals and understand the issues impacting on each business
- met 4 times with the AusNet Customer Forum
- held regular discussions with AER coordination and stream teams
- held discussions with consumer representatives and other stakeholders.

To date, CCP17 has provided the following advice to the AER:

- Response to the Preliminary Framework and Approach (F&A) for Victorian Distribution Businesses – November 2018
- Comments on the AusNet Services Customer Forum Interim Engagement Report - 6 February 2019
- Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset – March 2019
- Comments on the Draft Regulatory Proposals (Draft Plans) – July 2019 (for each business)
- Customer Service Incentive Scheme Issues Paper – August 2019
- Draft Customer Service Incentive Scheme – February 2020

Matters considered in this presentation

1. Consumer Engagement
2. Revenue, price and RAB
3. Operating expenditure, including step changes
4. Capital investment
5. Solar enablement and future network
6. Forecasts
7. Depreciation
8. Incentive schemes
9. Tariffs
10. Metering and ACS
11. 6 month extension
12. Assessment of AusNet's proposed opex and capex

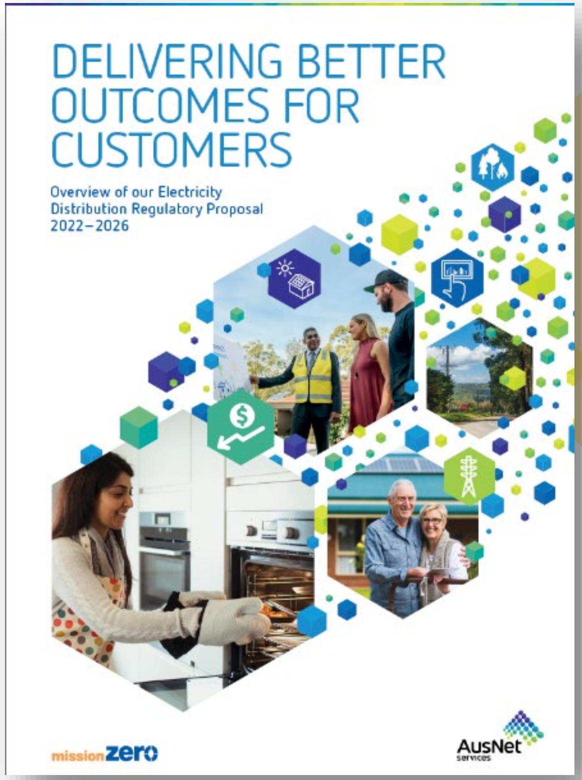
Consumer Engagement

Consumer Engagement – general comments

- All business have actively engaged and started early
- Different methodologies have been applied, eg Scenario planning, People's Panel, Customer Forum
- Significant improvement in the quality of engagement across the NEM and capacity of NSP's to hear what consumers say
- The 6 month extension lost some momentum
- All DNSP's participated on joint consultation on tariffs
- The volume of documentation in the proposals made detailed assessment of the proposals difficult
- We saw some common themes:
  - Future Network uncertainty and responses / Distributed Energy Resources (DER)
  - Responding to Bushfires and associated risk
  - Minimal consideration of Demand Management
  - Some movement along IAP2 spectrum from "inform/consult' to "involve/collaborate"

AusNet Services

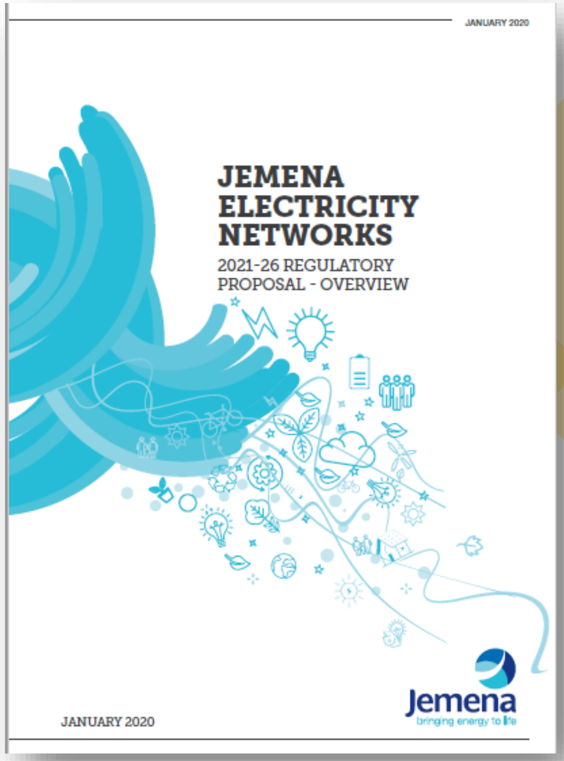
- The major focus of AusNet's consumer engagement was the work of the Customer Forum, the centrepiece of the NewReg Trial.
- According to the guidelines established for the NewReg trial, CCP17 did not participate as an observer in consumer engagement activities undertaken by the Customer Forum
- However, we did observe:
  - 1 Community Energy Forum hosted by AusNet Services
  - The Customer Forum's progress updates on their negotiations for consumer representatives
  - Deep Dives on the Draft Plans conducted by AusNet (Customer Service, Opex, Capex, ICT, Innovation, DER)
- The Proposal strongly reflects customer perspectives for those aspects within scope for the Customer Forum
- The Customer Consultative Committee is ongoing
- We note that AusNet has a higher proportion of proposal documents flagged as 'confidential', and question the reasons for that.



Jemena Electricity Networks (JEN)

Jemena applied a range of consumer and stakeholder engagement approaches

- People's Panel was the 'centre piece' of engagement a strong methodology:
  - included recommendations direct to Board – ceremoniously presented as a scroll
  - Panel recruited to reflect demography of the JEN region, 43 participants
  - A total of 6 extended sessions over 6 months
  - Active two way engagement in all sessions
- Customer Council ongoing
- Focus Groups with Households, SME's, C&I. Including 20 direct sessions with small businesses.
- Local Government engagement, including street lighting
- Proposal gives good evidence of customer perspectives
- Jemena (JGN and JEN) were winners of the ECA /ENA engagement award in 2019



CitiPower, Powercor & United Energy (1)

CitiPower, Powercor and United Energy ran their consumer engagement based on a consistent approach and using the same Melbourne based staff for each engagement activity.

Much of the material used and timelines for consumer engagement activities was published on a single website, where customers could also:

- Read information regarding the businesses and their consumer engagement activities
- Find out about the 2021-25 reset process
- Download key documents
- Provide comments on a ‘Contact us’ form

The consumer engagement activities regarding the upcoming regulatory proposals were branded “Energised 2021-2025”.

CitiPower, Powercor & United Energy (2)

The consumer engagement activities commenced with the publication of a single Regulatory Reset 2021-2025 Stakeholder Engagement Plan in November 2017 that covered all three businesses – CitiPower, Powercor and United Energy.

This Engagement Plan set out four phases of activities that the businesses would be undertaking. These phases included:

- Understanding customer preferences (2017)
- Exploring future energy scenarios (2018)
- Engagement on the Draft Plans (2019)

The Engagement Plan also set out the engagement platforms that the businesses would be using, which included newsletters, the Talking Electricity website, pop up displays, focus groups, interviews, surveys, meetings, workshops, an advisory panel, and communication around the businesses' Draft Plans.

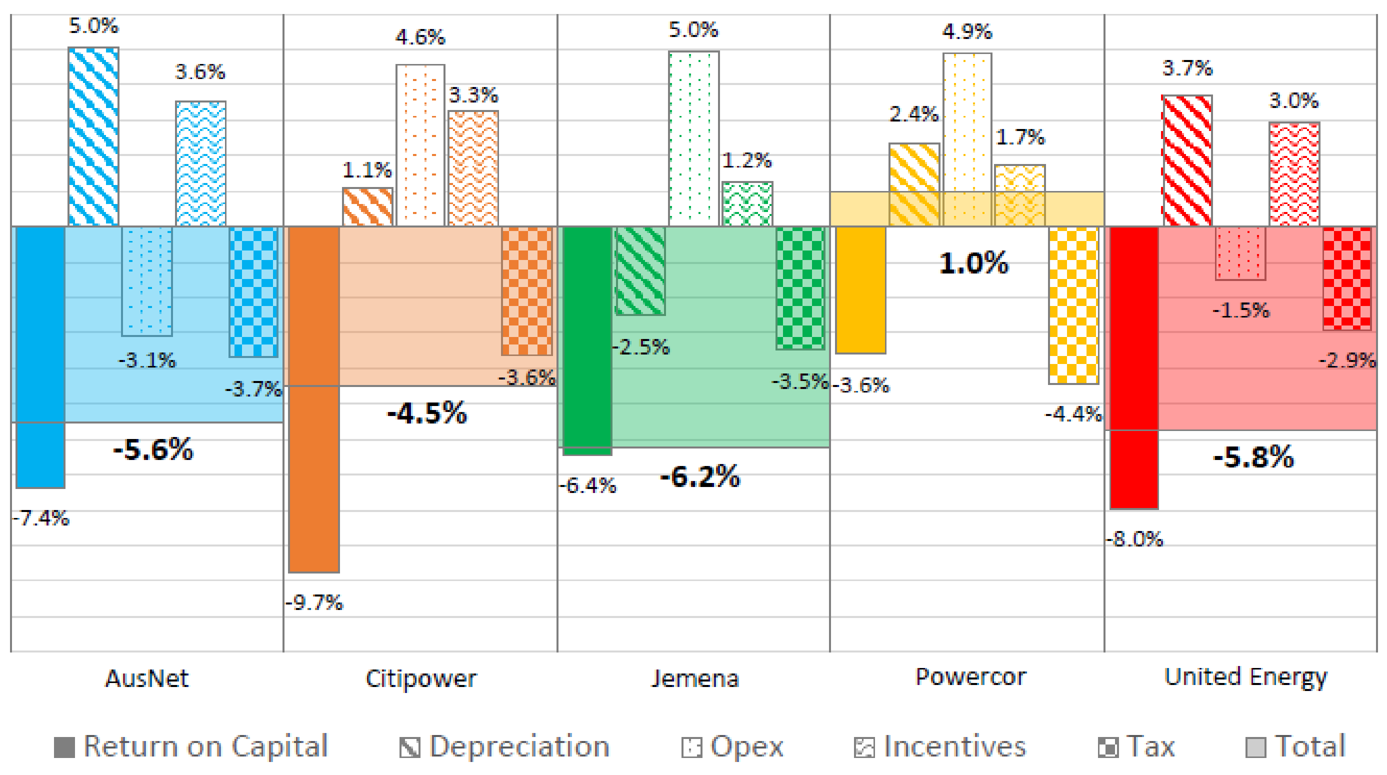
Since its inception in November 2017, CCP17 has liaised closely with the three businesses.

We sent at least one CCP17 representative to most of the events to which we were invited, but clearly did not have the resource to attend every event. We have generally encouraged the businesses on the paths that they have chosen, on the shared understanding that not every consumer engagement activity will prove successful. The businesses were on a steep learning curve, and much learning came from trial and error.

Revenue, price and RAB

Drivers of Revenue Change (SCS & metering services)
- a great graph

1. Note the impacts of declining Return on Capital, biggest reductions in price impacts for all businesses except Powercor (tax allowance reductions bigger)
2. Opex main driver of pressure for price increase for JEN, CitiPower, Powercor
3. Depreciation main upward price pressure for AusNet Services and United Energy
4. Reducing opex for United Energy and AusNet Services
5. The lower return on capital savings for Powercor at 3.6 % doesn't align with other businesses, we wonder why?



There are significant cost reductions driven by external to business factors, such as allowable Return on Capital and the tax allowance. The businesses' controllable costs are rising. Without these external factors, we highlight that there would be an increase in total revenue and likely subsequent price increases as a result of these proposals.

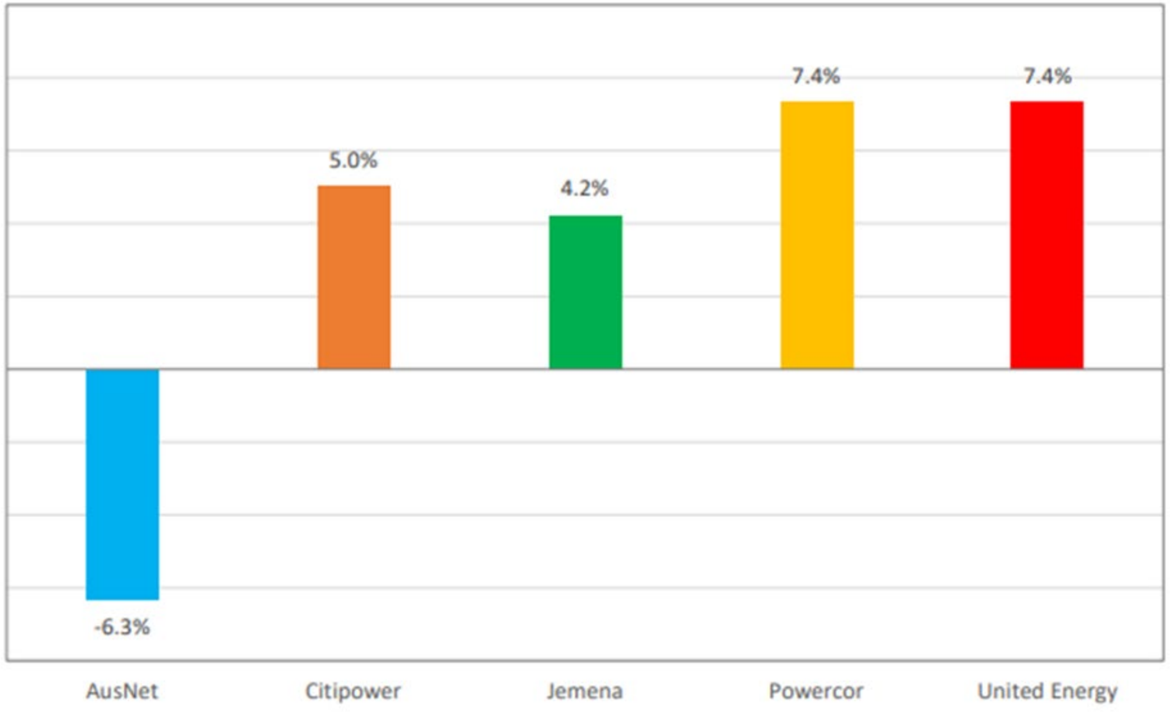
Revenue, price and RAB trends

All networks note in their engagement, the strong preference by consumers to restrict price rises.

However, the level of investment, leading to the increase in the regulated asset base per customer (for all but AusNet), raises real risks of significant prices in the future if and when the allowable return on assets increases.

In our assessment, we look for evidence where utilities have considered a revised risk position, the application of innovative solutions and the fact that ‘not every NPV positive project needs to go ahead’ in order to respect the customers’ desire to restrict future price rises.

Figure 10 Difference between proposed opening and closing RAB per customer – 1 July 2021 to 30 June 2026 ($real June 2021)

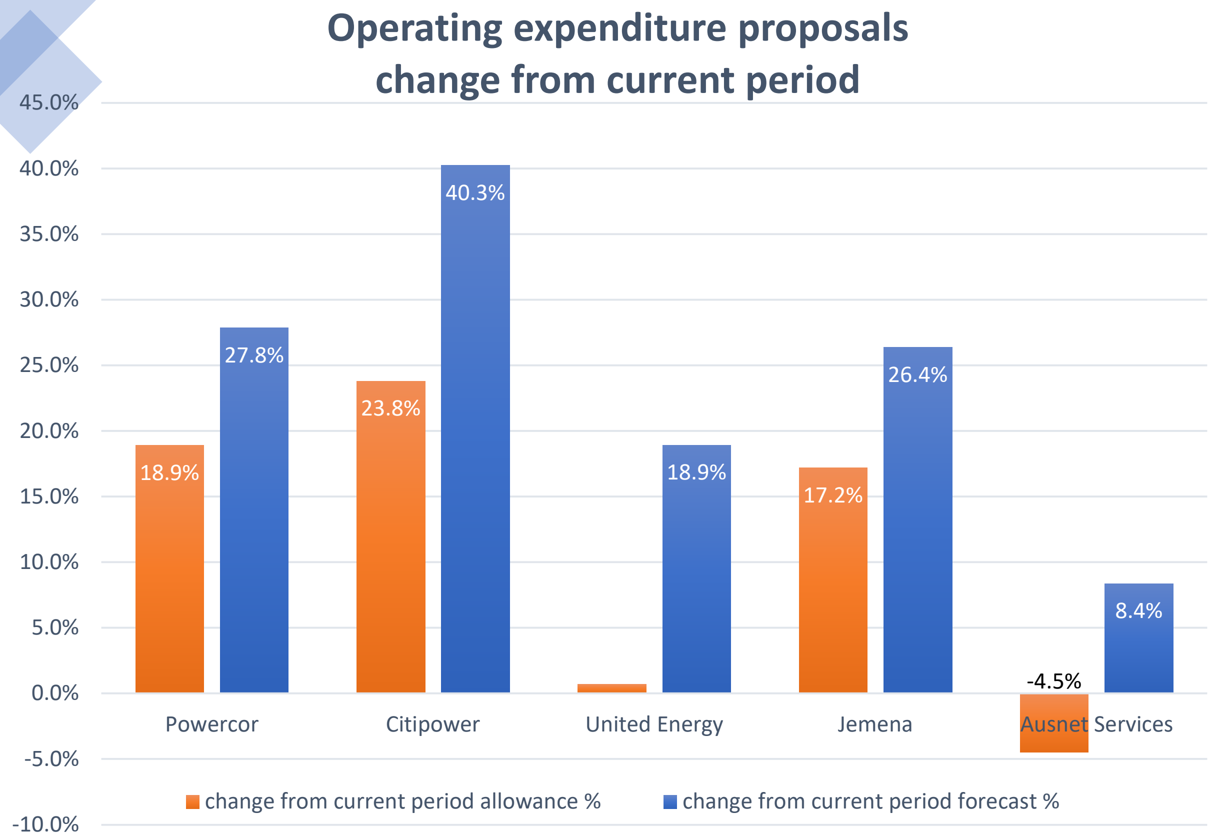


Note: Changes are determined in real terms – that is, excluding the effects of inflation.

Source: AER analysis using PTRMs for the 2021-26 regulatory period.

Operating expenditure

Operating Expenditure Proposals

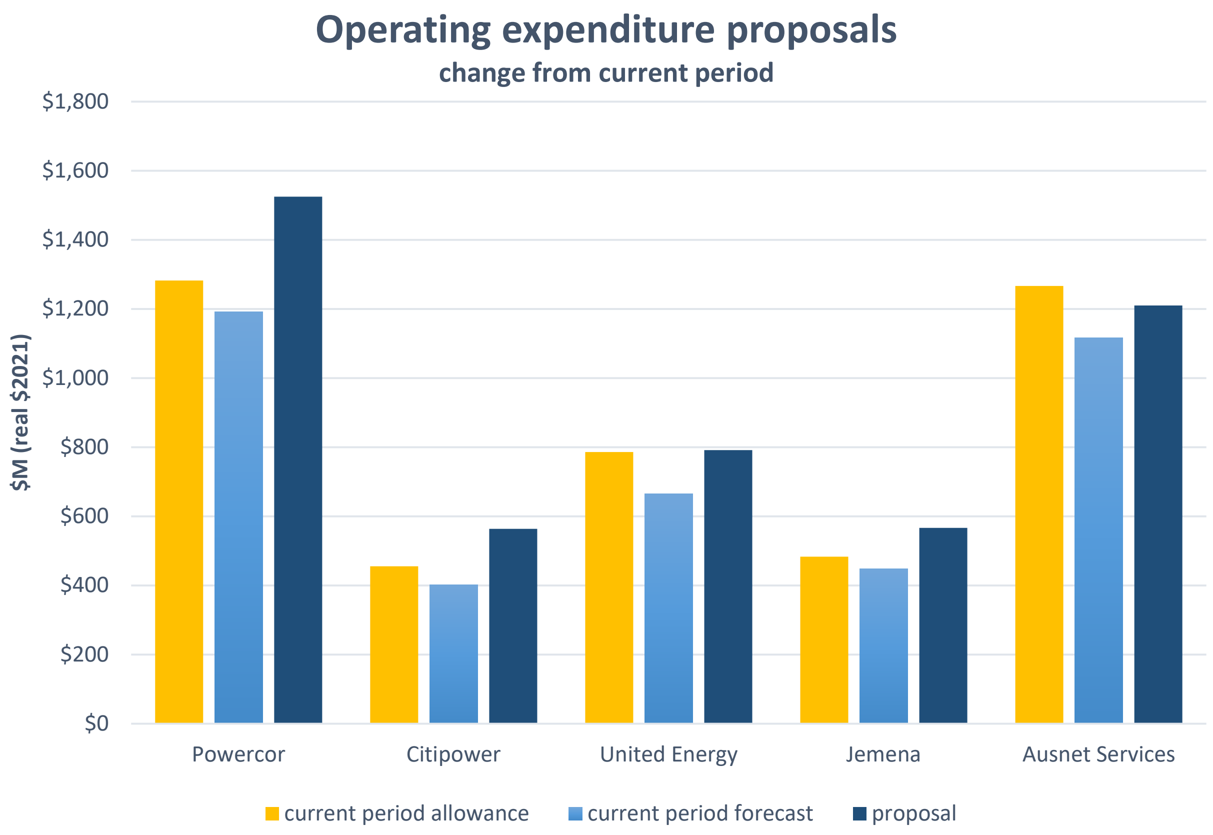


Opex change ($2021)	Proposal $M	Change from current period allowance (%)	Change from current period forecast (%)
Powercor	$1524.9	18.9%	27.8%
CitiPower	$563.7	23.8%	40.3%
United Energy	$791.3	0.7 %	18.9%
Jemena	$566.6	17.2%	26.4%
AusNet Services	$1209.6	(4.47)%	8.4%

- All networks are seeking opex increases compared to the forecast expenditure in the current period, notably Powercor, CitiPower and Jemena at over 20%.

Operating Expenditure – initial considerations

- All networks are seeking significant increases for opex allowance in the 2021-26 period, above what they are likely to spend in the current period.
- Opex allowances have increased for all 5 businesses over the last 2 regulatory periods, some increases have been significant. Although there have also been some efforts to reign in opex costs.
- All Victorian DNSP's have underspent their opex allowances during the current period. How should this be understood against the bids for higher opex cost allowances for the next period?
- When compared with the regulated opex allowance for the current period, only AusNet services is seeking less.
- Main drivers are step changes, cost reclassifications, demand growth (in particular outer Melbourne residential) and "Solar enablement."
- Our main focus is on step change proposals, noting that there are some recurring step changes from the May 2016 final determinations, for example; increased costs for producing RIN data was accepted for the current period (except for AusNet Services), have RIN costs increased to warrant another step change?



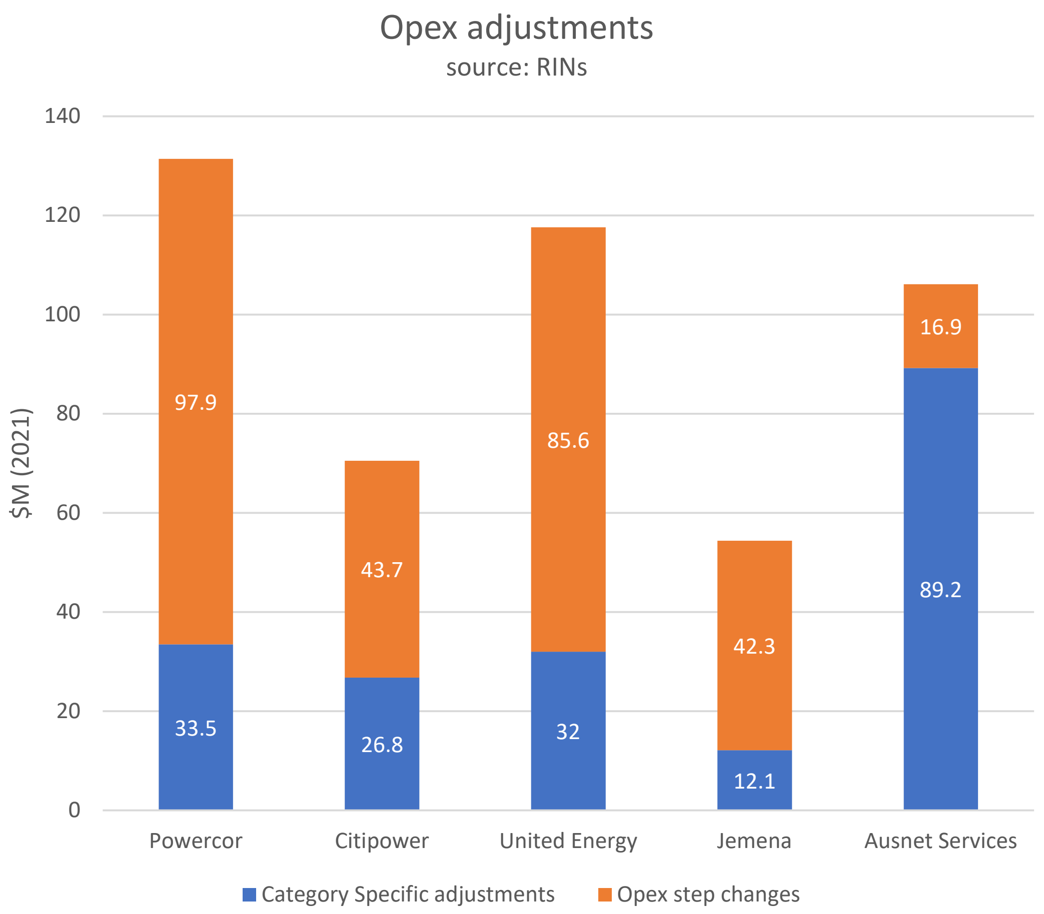
Operating Expenditure adjustments

All networks are seeking significant increases in their opex allowances through adjustments and step changes.

There are some notable issues in the approaches across businesses, such as:

- CPU choosing to reclassify some minor line repex as repairs ($18 – 26M)
- The cost to undergo operational changes to meet cybersecurity obligations can vary significantly based on current organisational arrangements
- Some AMI costs are being transferred to SCS
- Most utilities continue to invest in ICT cloud services. The capital savings from this action are not clearly evident as ICT capex reductions.
- REFCL systems require ongoing attention, such as tuning, representing ongoing costs of up to $13M in Powercor's case.
- AusNet seeking a significant GSL adjustment of $46M, noting the in the RIN as 'payments for failure to meet GSLs'.

CCP recognises that many of these changes result from legislative and industry requirements, although we seek further clarification that some of the proposed adjustments are valid, efficient and demonstrably a recurring operating cost of the business. (see next slides)



Operating Expenditure adjustments

Category Specific adjustments	Powercor	Citipower	United Energy	Jemena	Ausnet Services
GSL adjustment				0.17	46.7
AMI (comms and other)	7.4	3.1	4.7		29
Wasted truck visits	6.1	2	1.1		
Reclassify minor repairs	18.8	20.5	26		
Emergency recoverable works	1.25	1			
Innovation					1.2
rate of change 2020 + 1/2 2021					
TOTAL	**33.5**	**26.8**	**32**	**12.1**	**89.2**
Opex Steps	**Powercor**	**Citipower**	**United Energy**	**Jemena**	**Ausnet Services**
5-minute settlement	4.9	1.9	3.9		3.6
Cybersecurity	14.5	14.4	45.9	2.9	4.7
EP amendment	9.6	6.1	11.8	4.2	
ESV Levy	4.0	1.5	2.5	6.9	adj to base year
Financial Year RIN	1.8	1.8	1.8	0.5	
Yarra trams		14.4			
Insurance premiums	5.0		2.2	28.8	
REFCL ongoing	13.3			1.3	5.9
Reclassification HBRA	21.5				
Debt raising costs				4.3	11.8
Solar / Future grid	6.2	1.3	4.2	3.8	
IT cloud migration	5.9	2.3	4.7		2.6
EDO fuse replacement	11.2				
other			8.6	0.9	
TOTAL	**97.9**	**43.7**	**85.6**	**42.3**	**16.9**
Total opex adjustments	**131.4**	**70.5**	**117.6**	**54.4**	**106.1**

Information taken from information notices (RINs)

Note column subtotals may not add due to some businesses classifying items differently (grey shaded cells)

$M 2021

Opex Step Changes: Criteria

Step Change Criteria	Exogenous Obligation	Capex / Opex trade-off	ongoing	Comment
5 minute settlement	✓			Probably material and imposed. Timing impact?
Cyber security	✓			
EP amendment	?			BAU cost? Materiality?
ESV Levy	✓			
Financial Year RIN			✗	Seems
Yarra trams			✗	One-off cost? doesn't meet criteria?
Insurance Premiums	?			Is Materiality of increase relevant? Yes.
REFCL ongoing	Part ✓	?		Some already contingent projects. Efficiency of expenditure
HBRA	✓			
Debt Raising Costs	?			BAU cost? Materiality?
Solar / Future Grid		?	✓	Wait for SAPN/EQ decisions
IT Cloud mitigation		✓		
EDO Fuse	✗			Looks like a standard business cost
GSL Scheme	?			Customer Forum view significant
Other				Mainly UE and ANS
Metering Cost	?			
Innovation		?		Customer Forum support

✓	Means that the proposal appears to meet the step change criteria, subject to reasonableness of unit costs and project plans
?	Means that it is not obvious that step change criteria are met, further clarification or exploration is required.
✗	Means that CCP is not convinced that the step change criteria has been met.

Other operating expenditure considerations

1. Base Year - there is some concern about the efficiency of the base year for AusNet Services and JEN, (see benchmarking data previous slide)
2. Labour cost escalators - There have been no real income increases for many customers in a very low income growth environment, so proposed labour rises seem out of balance with customer incomes. The economic slow down implications of COVID19 also mean that these cost escalators will have to be revised.
3. Opex / Capex trade-offs, what are the implications for customers? There has been active consideration and application of a range of opex / capex trade-offs for a number of years. Is there evidence to show that customers are benefitting from these trade-offs, in reality?
4. The opex productivity improvement (minimum 0.5 of a percent improvement) is not obvious
5. Responding to bushfire risk. Victorian DNSP's have spent considerable effort responding to the horrific 2009 fires and a decade later – another horrific bushfire summer. We expect some revision of recent bush fire impacts in the revised revenue proposals and expect detailed engagement with consumer groups about any changes.
6. Impact of COVID19, this is still largely unknown and is another topic that we expect will be carefully considered in consultation for the revised revenue proposal.

(Note: Consumers have welcomed energy business responsiveness to COVID, for example through the ENA and Energy Charter, provided these initiatives are properly targeted. How these initiatives are funded in the longer term is also of concern.)

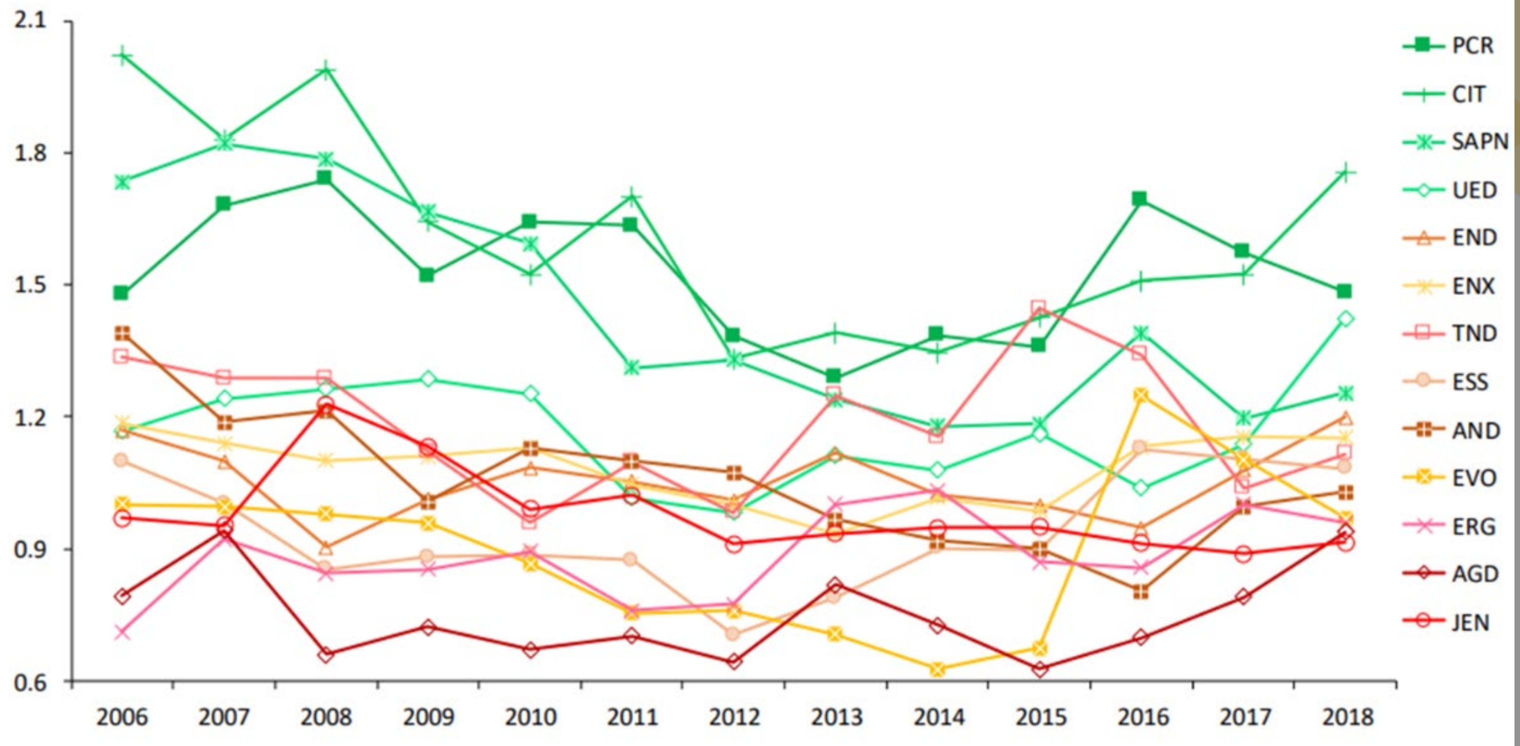
Opex Base Year

Opex multilateral partial factor productivity (MPFP) from AER benchmarking report 2019 shows:

- JEN & AusNet are in the lower range re opex efficiency, though improving over recent years.
- ‘CPU’ group are in ‘best 4’, though UE MPFP declining.

Leads to questioning whether base year is efficient for all Victorian DNSP’s

Figure 4.3 DNSP opex multilateral partial factor productivity indexes, 2006–18



Source: Economic Insights, AER analysis.

Capital Investment

Capital Investment – general preliminary comments (1)

1. CitiPower, Powercor and United Energy (CPU) propose increases relative to the expected capex investment for the current period. Whilst this top-level comparative information is powerful and important, it is difficult for consumers to difficult to assess, especially for Powercor, JEN and AusNet when significant expenditure for REFCL projects is embodied in current and proposed expenditure. We have attempted to treat much of REFCL as a one-off project, whilst recognising the significant ongoing costs.
2. Every utility is proposing a significant *capital efficiency carryover*. Underspending an allowance then asking for an increased capital allowance in a subsequent period draws consumer interest, where we ask the question 'if it is so important, why not get on with it now ?'.
3. With perhaps the exception of some inner-Melbourne networks, the companies *share a common SECV heritage* for long term network assets such as substations, power transformers and switchgear, in terms of design, supplier, application and maintenance. Similarly, they operate largely in the same safety regime through the ESCV. This provides an opportunity for some comparison between the companies in terms of asset replacement drivers and bushfire mitigation activities. Our first assessment of the proposals highlights:
   a) The disparity in the approach taken to pole failure risk between the CPU companies and others,
   b) A high level of variability between businesses regarding the costs to respond to the recent changes to the state environmental protection legislation, and
   c) A reasonably common approach to meeting the challenges of increased penetration of rooftop solar generation and enhanced visibility of LV networks.
   d) We are somewhat sympathetic to the increased in replacement costs for substation primary plant seen in the proposals, in particular switchgear. This is a trend seen in urban and CBD networks in other states.

Capital Investment – general preliminary comments (2)

4. A number of utilities intend implementing *SAP S4/HANA* around 2024. Should there be concerns for the industry capability to deliver efficiently ?
5. The companies note some investments that are intended to deliver *better customer service* / enablement. These projects should also deliver efficiencies to the DBs themselves – where is this reflected in the proposals ?
6. We expect that the utilities will consider the impact of the looming *economic downturn* in their forecasts and final proposals late in 2020
7. All utilities have noted a priority to replace service cables through some form of blanket replacement programme beyond failure-related replacements. This approach has been taken in other states, such as Qld with the replacement of a particular brand of cable. The utilities have made a case for a replacement programme, despite the fact only CitiPower specifies the important role that AMI can play in identifying hazards. For transparency and efficiency, we encourage the AER to consider a common risk assessment and mitigation approach to service wire hazards across all businesses.
8. The high level of investment proposed by CPU to respond to the changes to the EPA act do not appear to be well justified by fact and customer feedback in our observation. We would like to see a greater level of detail, actual reports of non-compliance and rigorous options analysis before supporting the proposed expenditure. The fact that such high levels of investment requirement are not reflected in JEN and AusNet appears inconsistent.

Capital Investment - Powercor

1. The proposed significant increase in pole replacement expenditure by the CPU companies is of concern. We acknowledge the mood of the Warrnambool customer forum where there is pressure for Powercor to take some action to provide more confidence to the community regarding pole failures and fire risk. However, we would like to see:
    a) A broader conversation that encompasses the impact of revised pole inspection and asset management practices and the risk reduction as a result of the REFCL investment, rather than focus on a more conservative pole replacement programme. It would be helpful for the companies to note the consideration given to 'non-asset' approaches to pole failure risks (and ultimately public risk and fire start risk).
    b) A stronger level of analytics of actual and observed failures and data to support the proposal for age-related assets.
2. We believe that the proposed opex step for EDO fuse replacement ($11M) is more appropriately considered a capital investment. In addition, it could be considered as 'business-as-usual' repex obligations within existing funding.
3. We note the continued high level of connections activity in the Melbourne – Geelong – Ballarat corridor. We support the AER's review of the Powercor connections policy.
4. CCP has concerns about the investment in the customer information portal. Whilst we acknowledge that customers can benefit from more timely usage information, we question whether such a facility is best developed by a regulated network business with costs shared across all consumers.
5. Similarly, we question the investment by all consumers in the regional network development for the dairy areas. We acknowledge the importance of the sector, however we have concerns about the proposal for the development to be funded by all consumers, especially as we did not observe the matter being raised in engagement outside the local areas benefiting from the investment.

Capital Investment - CitiPower

1. The proposed level of investment in *pole replacement* ($58M) and service wires ($16.2) stand out, where the modelled repex significantly exceeds AER model. We understand that there may be some data issues with some modelling at this stage. Notwithstanding this information, we note:
   - The revised pole inspection and replacement plan seems to largely hang off the back of findings in the Powercor area. CitiPower is a very different service territory, with different risks and failure impacts. We do not recall the changed safety criteria for poles in the urban areas being raised in engagement. Therefore, it is important that CitiPower revise the case for increased pole replacement before it would be acceptable to the CCP.
   - Pole failure rates and network performance do not suggest there is an emerging issues with pole safety in the CitiPower area.
2. *Unmodeled repex* (pole tops, protection) exceeds current period, even without the impact of the environmental project
3. We are reasonably sympathetic to the capital projects related to CBD CB replacement ($34.6) and pits ($14M) based on our understanding of the age and failure risk of the plant. We now look to the AER to consider the individual justification and cost efficiency.
4. Like Powercor, we see the proposal for compliance with EPA legislation changes ($71M) to be lacking in justification and detail.
5. Like Powercor and UE, we are unsure of the investment ($11M) in the ‘digital network programme’. The purpose, payback and risks associated with this programme are not clear. How does this sit in a network that has already had significant investment in AMI and is also proposing other projects related to solar enablement and LV modelling. We are concerned that there is overlap in the scope and benefit realisation of these projects and seek a clearer, consolidated engagement regarding the scope, costs, and benefits of all projects that are intended to ‘build a smarter network’. Whilst we recognise that investments such as these may have a positive return both commercially and in customer service, we also refer to the imperative to keep prices and RAB growth manageable and ask whether these projects, funded by customers, are absolutely necessary ?

Capital Investment - United Energy (1)

1. Poles, service lines, Switchgear and Transformers all exceed AER repex models
2. Every category of capex increases from current investment this period
3. Repex, Poles - UE has concerns of increasing pole failures due to age, hence increased pole repex ($56 > $90M).
4. Condition-based pole interventions go from $53M to $75M (change of safety benchmark ?); and a risk-based replacement programme of $11.2M. Need to resolve this against:
    1. “To date, this approach has resulted in our network having amongst the lowest wood pole failure rates in Australia.” (p55)
    2. Status of ESV’s review of Powercor pole management practices
    3. Consequence of failure ?
    4. UE’s more rigorous pole inspection regime
5. Compare age-based risk justifying replacement of ex-SECV spec plant
    1. UE expecting an increase in ZS transformer replacements from approx. 1.5pa to 2.5pa ($32M) Same elsewhere ? New TXs also part of augex.
    2. Similar increased trend for 11KV CBs ($20M)
    3. Neutral screened service lines are a problem – supported by failure rate analysis ?
6. Service line failure plan ($24M) – yet annual failures are trending down since 2007. Majority of failures result in shocks. What is the role of AMI in mitigating the failure risk ? Business case would be more helpful if it clarified a program-based replacement vs replace-on-failure. Can they use the CP neutral detection development ?
7. Distribution transformer augmentation programme – it would help to have more visibility regarding how DM, innovative tariffs, solar and community batteries will influence the expected $19.1M (p103)

Capital Investment - United Energy (2)

Again, Capex proposed is higher than current period across every category.

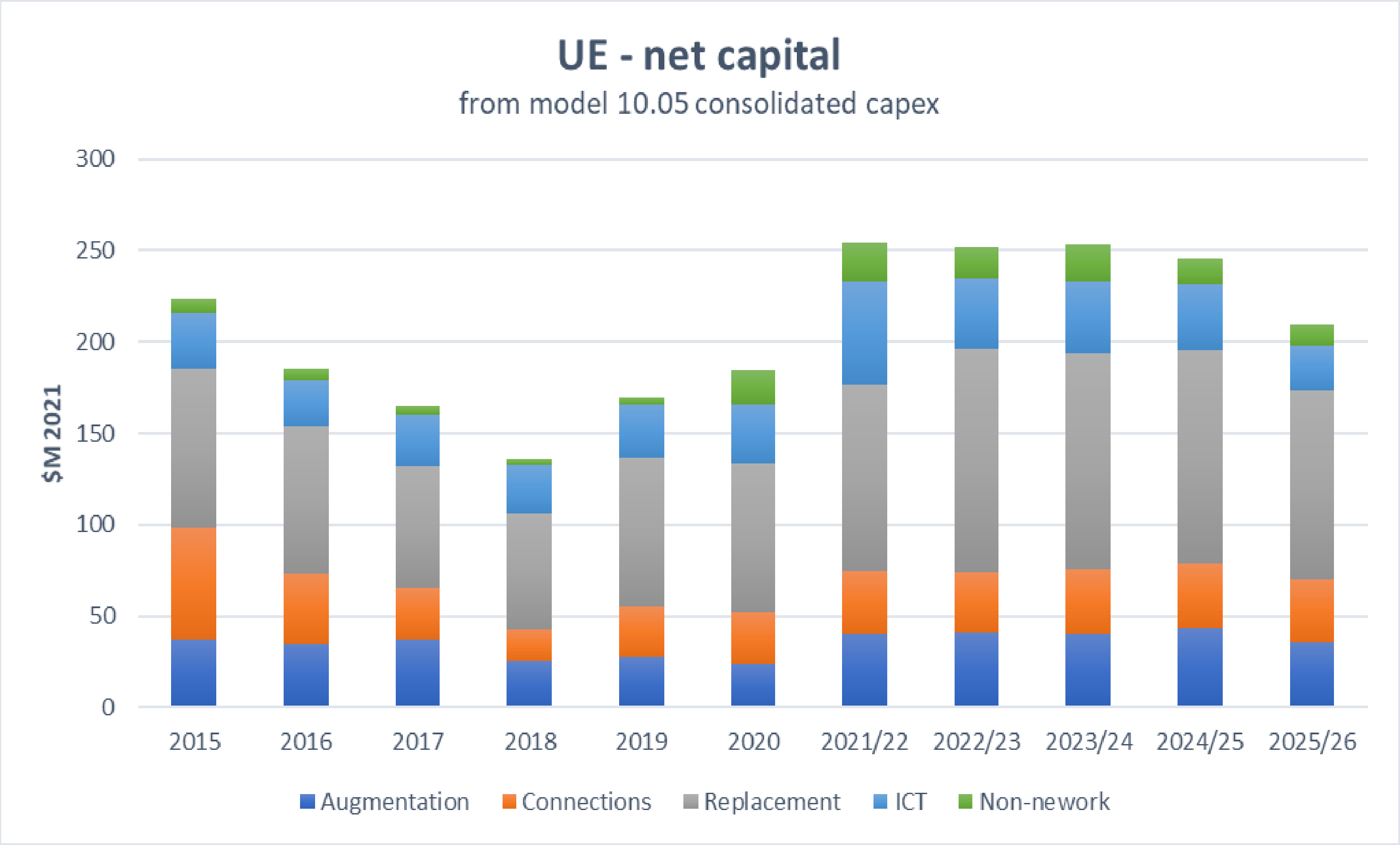
Do the drivers, observations and engagement outcomes support this pattern ?

Was the underspend from the current allowance genuine efficiencies, or has some work been carried forward ? This is not clear.

Increases to:

- Repex (mainly poles)
- Augex (solar enablement + growth)
- ICT – Solar enablement
- Environmental compliance
- Building refurbishment

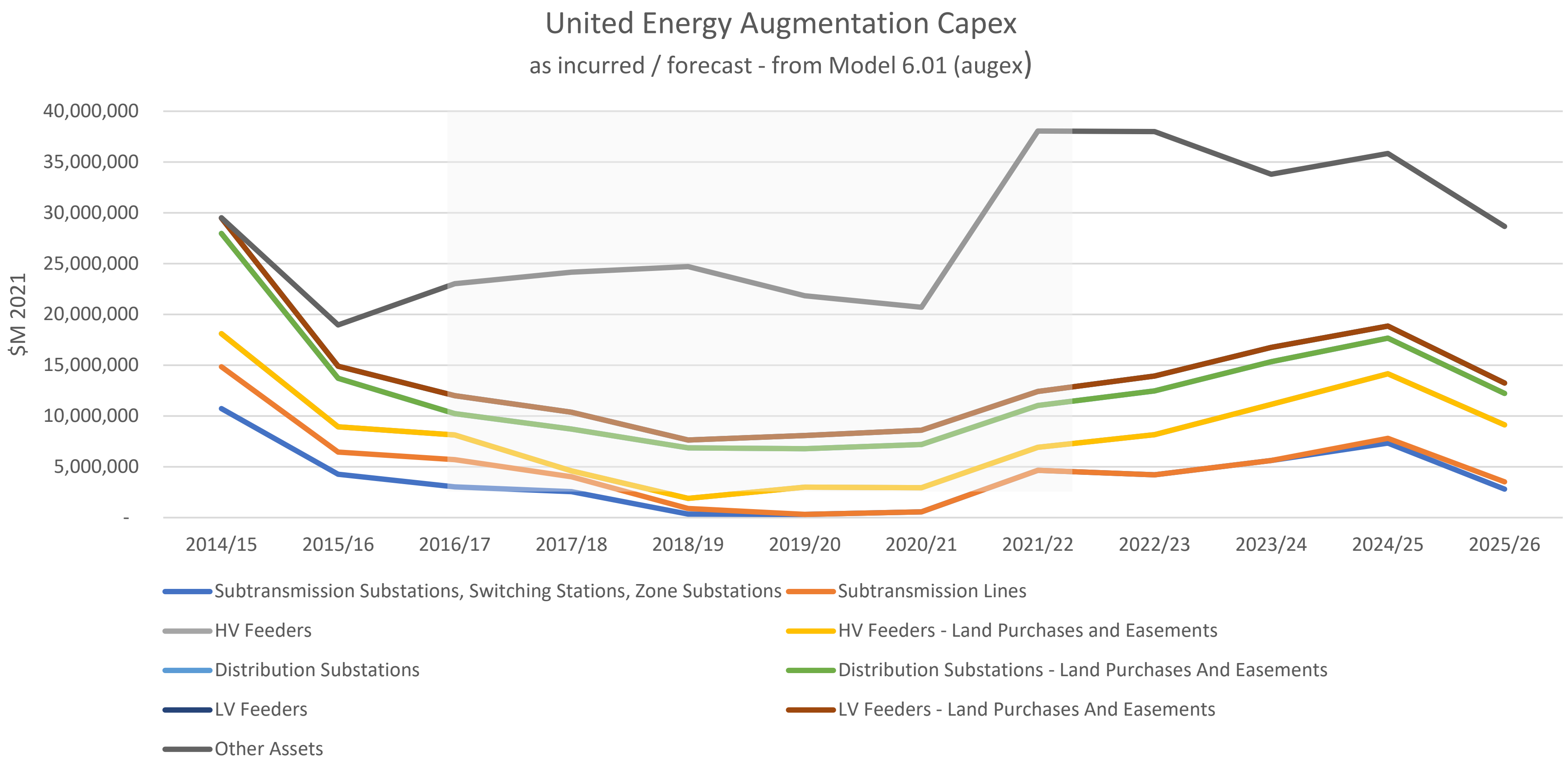
Note: similar issues apply to varying extents across the 5 companies. The data presented regarding UE is to illustrate the questions and focus that the CCP has on capital expenditure proposals for other distributors as well. It is not intended to suggest that these questions are unique to United Energy.



Capital Investment – United Energy (3)

Observation –

Augmentation proposed is higher than current period across every category. Do the drivers, observations and engagement outcomes support this pattern ?



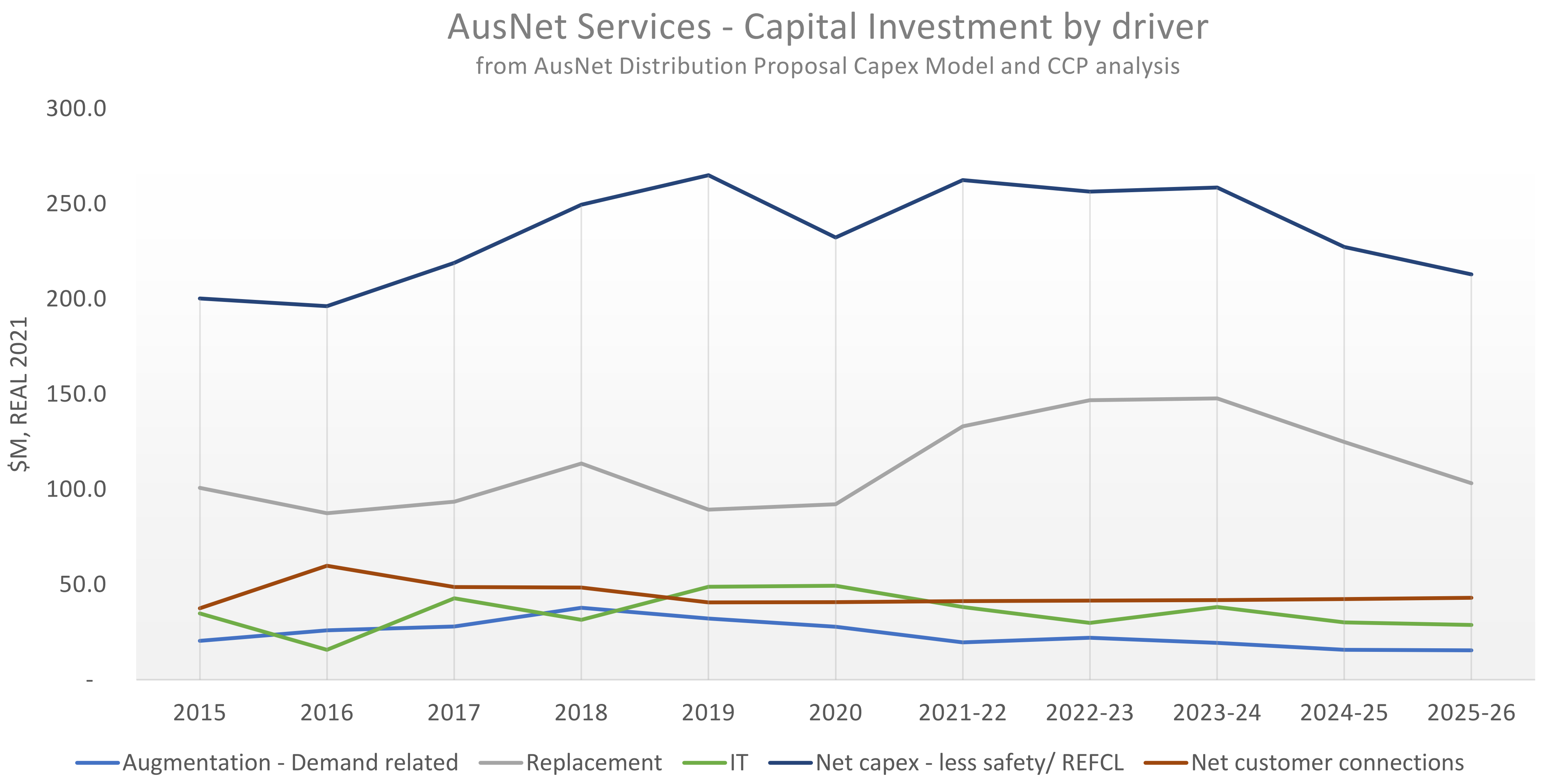
Capital Investment – Jemena Electricity

1. We note that JEN has changed its cost allocation model. It is understood that around $62M of capex overhead costs are now expensed. When considering that impact, we note that JEN is proposing an increase in capex of the order of 6%.
2. The one REFCL programme that significantly influences the capital expenditure is, we understand, uncertain as to how it will proceed.
3. JEN has made a reasonable case in its engagement to support the zone substation switchgear replacement programme ($26M) and the continued retirement of the 6.6kV system. In its community engagement, JEN specifically highlighted the risks associated with ageing network protective devices. We support the AER's consideration of this investment ($29M)
4. JEN has achieved ISO 55001 certification for asset management, which assists consumer confidence in their Asset Management practices

Capital Investment – AusNet Services (1)

1. AusNet note that the bushfire risk in their service area is amongst the highest in the world (proposal s6.1), and that the AER's annual benchmarking do not account for safety expenditure. AusNet states that around 90% of their network is in rural areas, similar to other rural networks in the NEM, being Ergon, Powercor and Essential Energy.
2. Ausnet has noted that whilst peak demand will increase, energy consumption will decrease. This supports the forecast of residential rooftop solar PV growth. Reliability is continuing to improve. Solar PV penetration is forecast to increase by 60% from 140,000 to 226,000 customers. It will be useful to see sensitivity analysis on pricing should the expected reduction be different to that forecast.
3. Around 7% of AusNet's capex has been within the negotiation scope of the Customer Forum. CCP17 was briefed about the negotiations and we raise no concerns with the CF recommendations on capex at this stage.
4. AusNet notes a proposed net capex $1,467M ($2021) as 21% lower than the expected spend this period. It would be very helpful to reconsider this claim in light of excluding the cost impact of the REFCL projects to allow a more objective comparison between the top-lines of the proposed capex and that of the current period ? (proposal s9.1) . *See graph next slide – the indicative trend of capex (less safety/ REFCL) suggests a stable then reducing capex investment trend. Overall, at this stage this is a supportable investment trajectory given the priorities expressed in the customer engagement.*
5. Similar to other networks, AusNet is proposing an increase in Repex - $543M s 14% higher than expected $476M in current period.
6. This period, AusNet has underspent the regulated allowance on Repex, safety (including REFCL), connections and ICT. The situation regarding augmentation is unclear as a result of the reclassification of some repex projects, as is non-network thanks to lease reclassification.
7. AusNet notes a number of DM trials (e.g. Mooroolbark, Mallcoota GESS) and there influence on growth augmentation, and also identifies overlaps in various works in a top-down assessment. This is a useful approach and assists in understanding the integration between initiatives.
8. AusNet has proposed 7.5M for nine 'innovation' projects. We are generally supportive of this proposal at this stage given a) the Ausgrid precedent for innovation allowance, and b) the nomination of a robust governance framework. (proposal s11.1)

Capital Investment – AusNet Services (2)



Bushfire mitigation

We recognise that utilities have a number of obligations regarding bushfire mitigation (BFM) activities, including meeting the legislative and recommended actions, including those overseen by Energy Safe Victoria, including the Powerline Bushfire Safety Programme and prescribed maintenance activities. In addition, we acknowledge the approach taken by the individual businesses under their own asset management strategies related to their specific risk assessments and cost benefit analyses.

As part of the engagement related to this reset, Powercor highlighted specific feedback from customers in the south-west regarding an expectation that greater action be taken to mitigate fire start risk from electrical assets.

Against that background, we wish to raise the following points:

1. Utilities have invested significant amounts in REFCL installations. It is difficult in their proposals to see how those companies incorporate (in their public engagement and primary proposal documents, at least) the reduction in the fire start risk resulting from the REFCL investment influences risk assessments in their asset planning and BFM works. CCP is keen to understand how the considerable REFCL investment has influenced the risk assessments and planned expenditure on more traditional bushfire mitigation (BFM) works such as fuse replacements and more conservative pole safety factors in areas protected by REFCLs. Whilst we agree there is no 'acceptable' fire start risk in the eyes of consumers, we believe that networks should at least be transparent in how they embrace the change in risk profiles (if any) that drive BFM investments.

2. We believe many maintenance activities and asset replacement related to BFM is 'business as usual' and to a large extent ongoing repex. Utilities have been operating programmes such as fuse and conductor replacement as part of BFM works for a long time. Any specific costs beyond current expenditure levels should be clearly explained as to why it is not part of day to day capital works.

3. We note some increases in costs, including opex steps, related to changes in the boundaries of BFM declared and high risk areas. Whilst we acknowledge the increased costs associated with these changes, we support the AER in assessing the prudency and efficiency of the proposals

Solar enablement and future network

PV Penetration

August 2018, the Victorian government announced the Solar Homes program: support for customers who install solar photovoltaic (PV), solar hot water systems and solar storage batteries.

Estimates for 454,000 new installations now to 2026 (currently ~396,000)

~$220m sought for solar enablement, mainly augex

We note that the forecasts were prepared prior to the current economic changes and acknowledge that they will almost certainly be revised in the final proposal.

We also note the work being done under the VA-DER project with ARENA and the AER to consider the value of embedded generation to all consumers.

PV Penetration	% 2019	% 2026	No 2019	No. 2026
United Energy	11	23	75,053	163,766
Powercor	18	34	133,401	288,928
Citipower	4	24	12,545	73,8445
Jemena	10	28	35,000*	98,000*
AusNet Services	19*	30*	140,000	225,500

** Note that the numbers with an asterisk are estimates that we have implied from percentages (JEN) and total numbers (AusNet) provided in draft plans. We have applied these numbers to customer numbers for these two businesses to obtain estimates to complete the table, for indicative purposes.*

Solar Enablement & Future network

The businesses have all engaged with consumers regarding the development of their networks to accommodate and support new technologies, in particular rooftop solar PV, battery storage and electric vehicles. All consumers have indicated support for this initiative. However, when it comes to specific actions, we are not convinced that consumers fully appreciated the many aspects of the enablement, such as:

- How critical is the 5kVA export capability that forms part of the distributors technical analysis ? Could it be 3 kVA or a different value ? Is the planning as stated by some utilities, for 95% of customers to export 5kW realistic ?
- Have the impacts of the updated (2019) inverter connection settings been seen yet ?
- Are we sure that the 'all customers pay' approach has the support of all customers ? We note the analysis by CPU on the charging options, although we question the conclusion reached that the costs be spread over all customers, despite the customer preference that 'connectors pay' (PAL BUS 6.02 p19)
- To what extent have customers been consulted regarding the implications of 'solar enablement'
- Have the benefits of existing investments, such as AMI and active network voltage control, been fully explored ?
- Has the possibility of reducing network voltage been considered, given that voltage reduction can be acceptable as part of the demand reduction schemes offered by some distributors ?
- Has the full range of tariff impacts to implement behaviours such as the 'solar sponge' been explored ?
- It would be useful if the companies could provide more confidence that programmes such as LV augmentation (eg CP $8.2M or UE Distribution Substation augmentation $24.1M) does not overlap with solar enablement investment.

Solar Enablement & Future network

Overall, we acknowledge the impact of the growth in residential and small commercial rooftop solar PV is having on electricity networks. Each utility has their own approach to for meeting these challenges, but they essentially cover the same requirements.

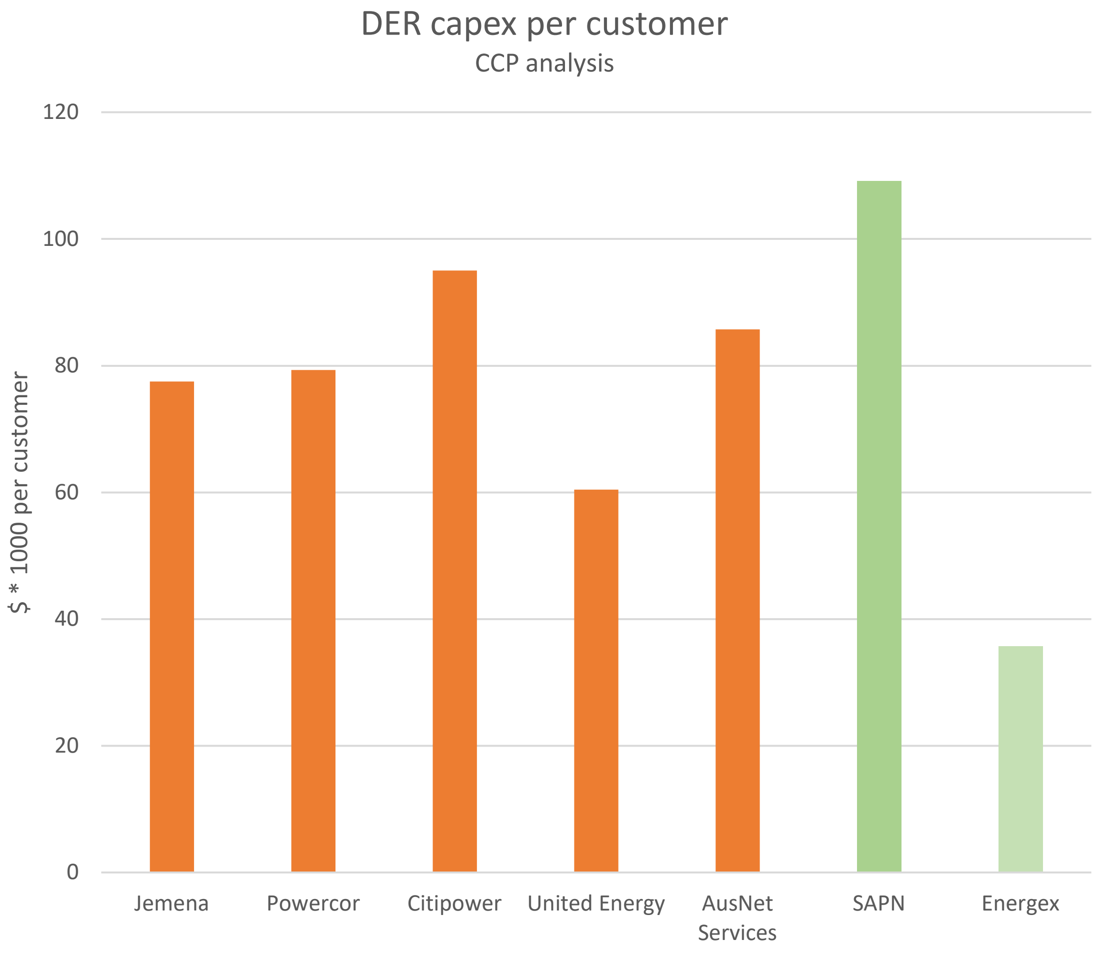
Utility	Programme	Purpose	Proposal ($2021)
Jemena	Enabling DER Optimised Asset Investments	Improved visibility of the LV network through a network model, enabling dynamic control Managing network investments to enhance generation hosting capability	$24.5 M Capex $5.1 M Capex $3.6 M Opex step
Powercor	Solar Enablement	Network investment ($58M), Dynamic Voltage Management System (2.45M) Opex is changing taps.	$60.7M Capex $5.6 M Opex step $1.1 M ICT
CitiPower	Solar Enablement	Network investment, Dynamic Voltage Management System Opex is changing taps.	$31.5 M Capex $1.3 M Opex step $1.1 M ICT
United Energy	Solar Enablement	Network investment, Dynamic Voltage Management System Opex is changing taps.	$42.5 M Capex $4.2 M Opex step $1.1 M ICT
AusNet Services	Hosting Capacity LV network capacity Voltage Compliance Prog DER enablement	Targeted augmentation to address emerging constraints (DENOP platform) Identifying emerging overloads Address 'least compliant' feeders currently non-compliant ICT works to support above, develop LV model	$20.9 M Augex $11.4 M Augex $20.6 M capex $11.4 M ICT capex

Solar Enablement & Future network

CCP carried out some basic analysis to consider the investment in solar enablement per customer (all customers).

Given the limitations of the broad analysis, it suggests that the amounts proposed by the Victorian companies compares reasonably with other states with high penetration of PV (SAPN – high PV levels, and Energex who are benefiting from a legislated voltage reduction).

We suggest greater scrutiny of the CitiPower proposal, given our expectation that the nature of the CitiPower distribution area is not conducive to large residential rooftop PV systems.



Forecasts

Forecasts

1. All Victorian distributors are forecasting growth in customer numbers, the circuit length of their networks and in maximum demand in 2021–26
2. Distributors are forecasting lower growth in energy throughput, with AusNet Services forecasting a decline in energy throughput over the forthcoming regulatory period
3. In general, we believe the forecasted peak demand increase may be overstated. Any impact of the expanded uptake of time-of-use for customers installing rooftop solar may counteract peak demand growth. Conversely, the use of reverse-cycle air conditioners, especially in new subdivisions, may also impact demand growth. We intend taking a closer look at demand forecasts, especially in the context of new housing growth and the uptake of new technologies such as electric vehicles. It is recognised that the emerging economic challenges will have an effect on forecasts, and we expect in the revised proposal utilities will revise forecasts and the impact on connections, large connections, solar enablement and demand-driven augmentation.
4. There are some deviations between AEMO demand forecasts and those of the utilities ? We note that AusNet highlights some reservations with recent changes to AEMO forecasting methodology (proposal s7.6.3), but the conclusions agree regarding their growth augex projects.
5. Forecasts of energy usage, peak demands and connections (new connections, and existing connections disconnecting) will need to be revisited in light of the impacts of COVID-19 on the economy. AEMO forecasts are also likely to be revised in light of COVID-19.

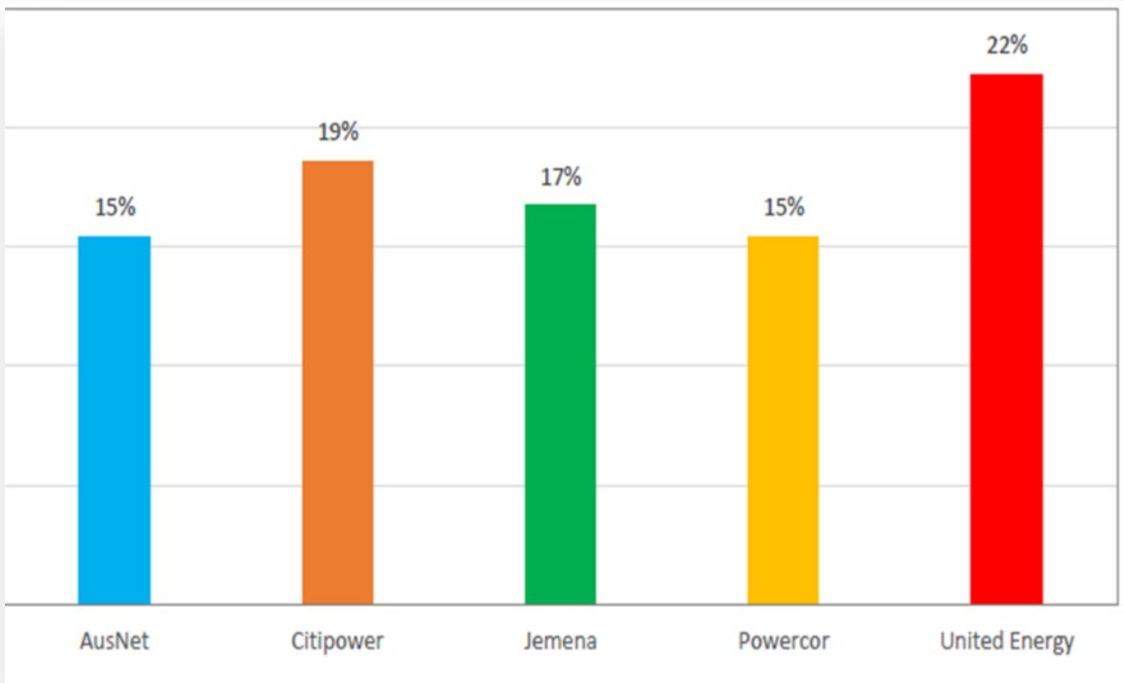
Depreciation

Depreciation allowance as a proportion of opening RAB

"Accelerated Depreciation"

- AusNet: $200m
- CitiPower $8m
- Powercor $74m
- United Energy $2m
- JEN <u>($8m</u>)
- Total $292m

NB: Accelerated Depreciation = assets with residual value replaced.
JEN = re-allocation.



Main “Accelerated Depreciation” Elements

- AusNet is proposing to depreciate ‘protection relays’ / ‘remote terminal units’ over 10 years; currently its over 45-50 years. ($200m)
- Citi Power, $7 million to replace older transformers for solar enablement. $1 million to replace PVC service cables ($8m)
- Jemena, no accelerated depreciation but proposing to reduce life for the existing ‘Non-network – other’ asset class to 5 years from 24. ($8m)
- Powercor, $39 million to replace REFCL assets. $35 million to replace distribution transformers for solar enablement. ($74M)
- United Energy, replacement of older transformers for solar enablement. ($2M)

Are Consumers getting good value for these accelerated depreciation elements?

CCP17 is not convinced by the large time changes for some assets by some businesses, eg devices currently depreciated over 45-50 years being depreciated over 10 years, or 24 year current life to 5 year. How do the proposed depreciation lives relate to the AER “roll forward model?”

Solar enablement depreciation needs further justification

Where reducing lives of assets makes sense, can the adjustment be made over 2 periods, rather than one?

Incentive schemes

Incentive schemes – Customer Service Incentive Scheme

- Throughout its advice to the AER, CCP17 has consistently supported the introduction of a CSIS, including the proposed revenue at risk
- In our most recent advice on the CSIS Draft Decision, CCP17 outlined the following concerns relating to the draft design of the scheme:
    - The need to include maintaining a 'social licence to operate' as an objective
    - Addition of a robust feedback loop in the overall process
    - Ensuring that there are not opportunities for 'double dipping', when combined with other regulatory allowances or incentives
    - Ensuring that the CSIS 'trial' is formally evaluated.
- We support Powercor, CitiPower and United Energy's intention to implement as CSIS, however question the feasibility of being able to adequately engage with customers in the timeframe to develop the design (noting current COVID-19-constrained circumstances.)

Incentive scheme carryovers

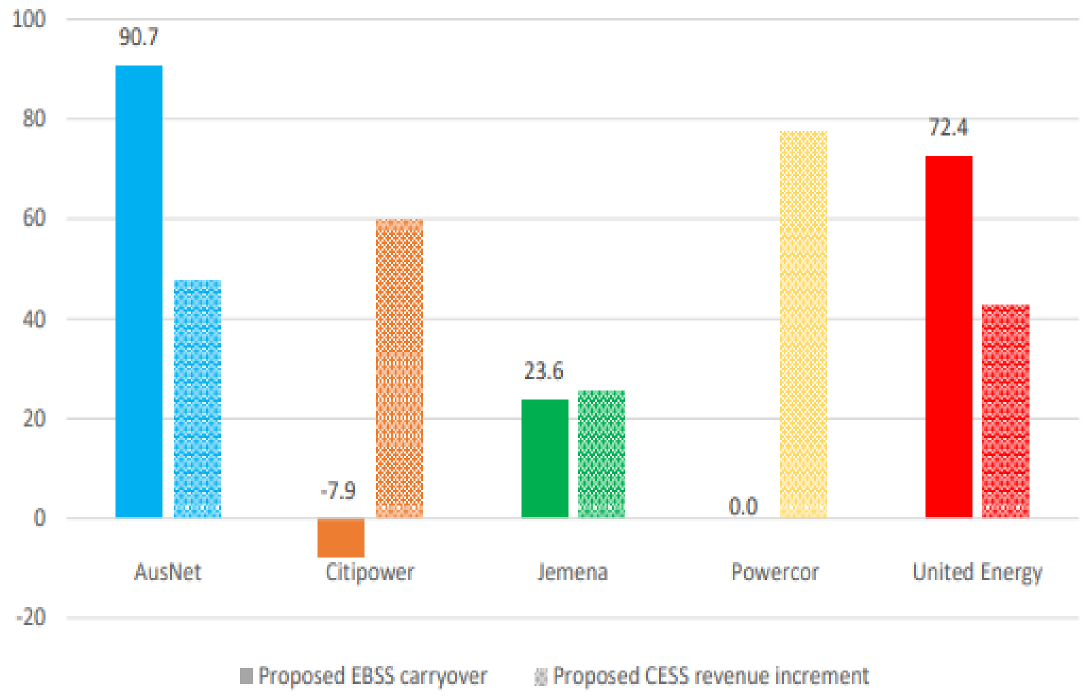
This diagram poses several questions for consumers:

1. How can the leaders in the electricity distribution efficiency benchmarks continue to deliver such significant efficiencies?

2. How do the efficiencies delivered sit with increased opex and capex in the proposals?

3. As per our earlier slide - Every utility is proposing a significant *capital efficiency carryover*. Underspending an allowance then asking for an increased capital allowance in a subsequent period draws consumer interest, where we ask the question ‘if it is so important, why not get on with it now ?’.

Figure 12 Proposed EBSS carryovers and ($million, June 2021) and proposed CESS revenue increment ($ million, June 2021)



Source: Regulatory proposal RINs.

Incentive schemes - STPIS, DMIS, DMIAM

All businesses are proposing to implement the new STPIS, DMIS, and DMIAM incentive schemes for 2021-26

Total Demand Management Innovation Allowances proposed are ($m):

AusNet	CitiPower	Jemena	Powercor	United Energy
3.46	2.0	2.0	2.8	2.5

Only AusNet has provided a list of projects it intends to undertake using this allowance

Demand Management was previously regarded as ‘using less’. The focus now needs to be a broader conversation that includes DER and future network, innovation, tariffs, capital deferment. We are looking where the companies are working with consumers to help them be ‘part of the solutions’ in the new energy environment.

CCP17 has not seen a lot of attention being paid to demand management in the proposals, with the exception of UE.

Tariffs and the Tariff Structure Statements

Summary of the TSS proposals

Section 2.5.2 of the AER's Issues Paper covers the role of tariff reform in supporting the transition of the energy system

The businesses' proposal follow from stakeholder engagement activities, including a series of customer forums on tariff reform

Residential customers

- A default time-of-use tariff will be charged to retailers for residential customers, with a peak charging window set as 3pm to 9pm and off-peak rates at all other times
- Alternatively, retailers will have the option of being charged a demand tariff targeting the peak period of 3pm to 9pm on workdays. Or the retailer can choose to opt-out of tariff reform and face a single rate tariff

Business customers

- For small business customers (<40 MWh pa), retailers will face a default daily time-of-use tariff with the peak set at 9am to 9pm workdays and off-peak rates at all other times
- There will be the option for the retailer to be charged a demand tariff targeting the peak period of 10am to 6pm on workdays, or the retailer can choose to opt out of tariff reform and face a single rate tariff
- This demand tariff will be the default for small business customers over 40 MWh pa

AusNet Services has proposed that for solar PV customers, the retailer can choose between a time-of-use or demand tariff, but cannot opt-out of tariff reform

The AER's indicated response / areas for analysis

1. The AER will look at the tariff proposals as an overall package and how they respond to the needs of customers and the challenges facing the networks – how do the distributors' tariff reform, demand management and other elements of their proposals work together as a package?
2. The AER intends to explore whether the peak periods that constrain each network are sufficiently aligned to the common residential and business customer charging windows proposed by the distributors
3. Is there merit in exploring a solar sponge charging window for areas with a high concentration of residential consumers to address the falling minimum demand associated with increased penetration of solar?
4. Have the businesses got the right balance between uniformity across the State as against addressing the specific locational issues of each network business / region?

Additional issues for stakeholder consideration

1. Are the tariff proposals cost-reflective as required under the Rules? Note that more complex tariffs do not necessarily indicate more cost-reflective tariffs
2. How will retailers pass on the tariffs to end use customers?
3. The AER describes various possible retailer approaches? Will different retailers offer different tariff structures? Will it mean that customers have more choice, or will it mean that customers who seek a particular retail tariff structure will be limited by which retailers offer that retail tariff structure?
4. What does modelling tell us regarding which customers would face smaller or larger bills with new tariff structures?
5. How will consumers make informed choices where they can choose between different tariff structures from retailers which are based on different underlying network tariff structures?
6. How will new tariff structures affect customers' investment decisions (in appliances, PV, solar, EVs)?
7. What will be the effects on vulnerable customers? How will vulnerable customers be protected from being put on tariff structures to which they are ill suited?
8. Should Solar PV customers be able to stay on flat tariffs?
9. With more complex tariffs, will network business revenue be more volatile, resulting in larger carry overs with revenue caps?
10. How does COVID-19 affect TSS? How will changed ways of working affect demand profiles – such as households using more power during the day through working at home, and with commercial and retail businesses closed. How will these short term changes be reflected in the longer term?

Metering and ACS

Metering

The companies have proposed a shift in some of the metering costs into Standard Control Services. At this stage, CCP is ambivalent to this change because:

- There is little evidence that metering will become a stand-alone contestable service in Victoria sometime soon
- There is a high level of overlap between the customer based receiving standard control services and metering services from the same company
- The application of AMI to improved network services is well-known and likely to expand in scope
- As customers install DER, stand-alone metering for DER control purposes will provide more and more customers with energy consumption data directly.

CCP will be interested in feedback from consumer groups regarding this proposal.

We also noted at least one utility (JEN) developing demand control devices that integrate with their AMI system. This work is encouraged, as the future of network utilisation and DER enablement relies on control and feedback capability, and levering off the existing AMI infrastructure is certainly worth investigation.

3G communications retirement

All utilities have noted the retirement of the 3G mobile communications system as a necessary cost in the next regulatory period; whether it be classified as an SCS, capital project or metering expense. We recognise this investment as inevitable, however we reiterate the mantra ‘ not a dollar too much, not a day too soon’. We therefore support the AER analysis as to the timing, changeover cost and options analysis regarding this change.

Public Lighting

- The trend to convert public lighting to LED systems continues. We acknowledge that the capital cost of LED luminaires and support structures can be higher than that of traditional lighting, with the trade-off of lower operating costs and the opportunity to implement new technologies (local networks, control).
- Some companies have also noted that they are not fully recovering their costs at present in meeting their lighting obligations.
- The companies are required to observe the Minamta Convention on mercury and the Victorian Public Lighting code in delivering their responsibilities and services to local government and state authorities.
- Many other utilities are required to meet similar obligations, and we encourage the demonstration that the Victorian distributors are engaging with these other utilities and, along with current experience, removing technical and commercial barriers in order to expedite the efficient roll-out of LED lighting. This includes minimising the time and expense spent on trials and tests.
- We note that some companies held specific ‘deep dives’ on public lighting issues, such as AusNet on the 27th Feb 2019. In those sessions, councils noted concerns about the cost of public lighting, including the risk of over-CPI price increases and significant costs to transition to efficient LED lighting.
- We seek a commitment that the utilities maintain an effective ongoing working relationship with councils and VicRoads to support these matters and maintain transparency in costs and service levels beyond that of the Public Lighting Code, noting that there can be a high degree of variability in the level of commitment by councils to implement energy-efficient lighting.

6 month extension

6 Month Extension

CCP17 supports:

- the approach of using a simple trended-forward methodology to establish building blocks based on the current (2016-21) regulatory period
- Application of 2018 RoR Instrument

We consider that a true-up should be applied post 2021 tariffs, if it is material

Assessment of AusNet's proposed opex and capex

Assessment of AusNet's proposed opex and capex

In the Issues Paper, the AER poses the question "*We are interested in …. the extent to which AusNet's proposal opex and capex are amenable to assessment at the total level with less detailed assessment at the level of capex and opex components, compared to other Victorian DNSP's proposals, given it compares well with peers, historical allowances and expenditure and the involvement of the Customer Forum in settling the proposal*"

In response to this question, CCP17 offers the following decision framework in relation to the items in the Customer Forum's scope :

- Can the outcome be presented as a demonstrably good overall outcome for customers? (i.e does it pass the 'pub test'? ; is it 'in the long term interest of consumers'?)
- Was the Customer Forum sufficiently resourced and informed to negotiate a reasonable outcome with AusNet?
- Were the proposed elements (eg. opex and capex) within scope for the Customer Forum?
- Did the AER provide subject matter guidance, for example 'reasonable ranges for negation of specific measures ('tramtracks') and did the Customer Forum negotiated result fall within this range?
- Does the overall outcome compare well with historical allowances & compare well with peers?
- If so, there may be scope for total level assessment of capex and opex components which meet the above criteria

Exceptions: Areas within its scope where the Customer Forum has indicated that detailed AER technical assessment of cost estimates is required

All 'out of scope' elements should be assessed according to AER's standard processes.

Consumer
Challenge
Panel

Photo: 66KV & 22KV lines, Powercor, 1997

Victorian electricity distributors
2021-26 Revenue Determinations

AER Public Forum
Consumer Challenge Panel