ELECTRICITY AUTHORITY
TE MANA HIKO

14 February 2025

s9(2)(a) [redacted]

Tēnā koe s9(2)(a) [redacted]

Thank you for your request, received on 20 January 2025, under the Official Information Act 1982 (Act) for the following information:

- *"in relation to ECTF work programme 2A any papers provided by the EAAG subgroup to TaskForce members and / or the Electricity Authority Board, any meeting notes that discuss this 2A topic and any other written communication from any EAAG subgroup members that the Task Force has received. This request relates to the timeframe since the Task Force was set up."*

The Electricity Authority Te Mana Hiko (Authority) is releasing five documents within scope of the request and seven documents that are outside the scope of the request but provide important contextual information.

The Electricity Authority Advisory Group (EAAG) had a pre-meeting on 28 August 2024. The Authority provided four documents to the group to inform the EAAG members on the proposals that support Energy Competition Task Force initiatives. The EAAG Chair was asked to form a subgroup to provide advice on these proposals. The subgroup was formed and held its first meeting on 17 Sep 2024 regarding cost-reflective pricing initiatives, this meeting was a verbal update.

The EAAG met on 23 October 2024. The Authority provided three documents to the group and two members provided feedback by email.

The EAAG met on 27 Nov 2024 to review the Authority's draft Board paper and on 3 Dec 2024 to finalise their advice to the Board. An EAAG letter was included in the Board pack for the Board meeting on Monday 16 December 2024.

Some information is redacted under sections 9(2)(a) and 9(2)(g)(i) of the Act to protect the privacy of natural persons and the free and frank expression of opinions respectively. To balance these two interests, and with section 9(1) of the Act in mind, we have redacted the identifying details of the two EAAG members that provided views while disclosing the opinions themselves.

Otherwise I am satisfied, in terms of section 9(1) of the Act, that the need to withhold the information referred to above is not outweighed by other considerations that render it desirable, in the public interest, to make the information available.

You have the right to seek an investigation and review by the Ombudsman of this decision. Information about how to make a complaint is available at www.ombudsman.parliament.nz or freephone 0800 802 602.

If you wish to discuss this decision with us, please feel free to contact us by emailing oia@ea.govt.nz.

Nāku noa, nā,

Airihi Mahuika
GM Legal, Monitoring and Compliance

From: s9(2)(a) & s9(2)(g)(i) [redacted]
To: Carl Billington; Jamie; EAAG
Subject: Solar export rebates for peak injection
Date: Wednesday, 30 October 2024 4:52:41 pm

Kia ora koutou,

Thank you for the opportunity to provide our input on this subject.

Our key concerns are:

- exporting solar generation into the grid requires the distributor to provide a different network service that does not mirror the infrastructure requirements for delivery of electricity lines services to the consumer;
- in some locations, providing the different service (feeding generation to the grid) may exceed the available capacity impacting reliability for all consumers in that area;
- rebating distribution prices at peak is a tool to lead consumer behaviour once DER is heavily penetrated and networks generally can deliver the new service, but given existing locational constraints it is an inappropriate uptake incentive;
- unless complex pricing is implemented that recognises locational constraints (and does not rebate in those areas) it will create inequity as all consumers will subsidise the distribution tariffs of solar exporters; and
- rebating of distribution prices at peak could result in reduction of distribution prices below subsidy free range (especially when combined with a home battery) leading to a subsidisation from consumers who cannot afford to benefit from emerging technology; and
- it may distort network use in a manner that increases investment needs (consumer incentivised to increase peak demand and require upgrades of the network).

A distributor providing a distribution tariff rebate for solar exported at peak does not promote the distribution pricing principles for the following reasons:

Distribution pricing principles	Comment	Whole-of-system solution
Prices are to signal the economic costs of service provision, including by: • being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs); • reflecting the impacts of network use on economic costs; • reflecting	Distribution rebates for peak injection signal to the consumer that there is a distribution network benefit to their investment and ability to provide generation at peak. That conflicts with a locational constraint that the consumer's investment and network use may exacerbate. The uptake incentive will increase the likely upgrade needs in some locations without the consumer understanding how or what could have reduced the investment requirement. The most likely areas with	A more equitable solution that consumers may more widely may benefit from is **fair buy back rates** through the retail market which recognises the benefit to investment in generation from solar generated downstream and exported to the grid at peak times. Promoting competition in the retail market through time varying retail feed-in pricing is more likely to

differences in network service provided to (or by) consumers; and • encouraging efficient network alternatives.	consumers who will respond to an uptake incentive are affluent suburbs where timely upgrades would require re-prioritisation of other decarbonisation/growth related projects. Generic **rebates will require a subsidy** where all consumers pay for the upgrades required to enable the delivery of solar export to the grid only benefitting some. Delivering solar back to the grid is a different network service provided both to and by consumers. The distribution investment is directly linked to locational capacity, as evaluated through the DG application process. If there is not adequate capacity to deliver exported load back to the grid, a future cost for the distributor is upgrading the constraint and directly a cost of providing that different service (enabling the export of solar at peak times at that location).	generate wholesale market benefits aligned to reducing generation investment need at peak times. This is aligned to modifying consumer behaviour in a manner that has a whole-of-system benefit (solar in the right place at the right time). While elaborate locational distribution time varying rebate, with a floor, to ensure adequate revenue from each ICP could support the retail market - the complexity would generate extra costs for the end consumers on the whole. **A competitive retail offering will provide a material incentive to the consumer** irrespective of a relatively minor rebate and avoids additional distribution complexity in pricing (alongside equity concerns).
Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	**Rebates** require the shortfall of revenue recovery (as per price-quality regulated entitlements) to be dispersed among all consumers which will **distort network use** because consumers who do not benefit from the rebate may: • modify their behaviour to reduce their vulnerability	The actual cost of distribution investment to relieve locational constraints should be factored into whole-of-system cost/benefit analysis. Other issues must be balanced appropriately,

	to the dispersed distribution charges (responding to the rebates) and their change in behaviour will not impact their tariff; and • be attracted to exporting solar into the grid to access the rebate which does not reflect the actual costs of the distribution investment required. **By using the distribution price to signal a whole-of system benefit, the retail market and consumer behaviour cannot respond to the real costs of investment that flow from solar export at peak.**	including that solar does not provide firmed security of supply and while batteries can, the cycling of batteries can necessitate further investments in certain locations. The value to the whole-of-system can be factored into that analysis alongside **how uptake incentives signal the most economically useful consumer investments**.
Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: • reflect the economic value of services; and • enable price/quality trade-offs.	Distributors make careful price/quality trade-offs that consider the needs of all consumers on their network without prioritising the needs of one category, i.e. solar and battery owners able to feed in. The DG application process recognises the network impact and provides load forecasting information for careful management in the long-term interests of consumers.	Whole-of-system considerations should retain the price/quality trade off inherent under the Part 4 Commerce Act 1986 regime (for non-exempt EDBs). Incentives on consumers and distributors will cut across one and other i.e. matching services to the quality expectations of consumers without the ability to apply cost reflective pricing to network use (52A(1)(c) and (d))".
Development of prices should be transparent and have regard to transaction costs, consumer impacts and uptake incentives.	The rebate will **distort calculations of the long-term marginal cost** of a solar and battery investment for a consumer. There is limited certainty rebates could remain as a permanent uptake incentive. We consider	Commercial deals maximising short to medium-term incentives that do not reflect the costs of service provision will misrepresent the long-term marginal cost to consumers (on the

	permanency is unlikely given the need to disperse costs of providing a different service to some consumers around other consumers who do not benefit from that distribution investment.	presumption a rebate will be a temporary uptake incentive).

Ngā Mihi | Kind regards

s9(2)(a) & s9(2)(g)(i)

[redacted]

Taskforce recommendation 2A: requiring distributors to pay a rebate when consumers export electricity at peak times

18 October 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Questions for EAAG

- **What do you think of our initial preferences in terms of high-level options?**
    - Rate? (including any adjustment factor)
    - Period?
    - Location?
- **What do you think of our initial preferences in terms of design factors?**
    - Customer type
    - LFC customers
    - Customers on non-TOU tariffs
    - ICPs contracted to VPPs
    - Rebate limits (export size, rebate size)
    - Policy duration

Other specific questions

- Do our preferences strike the right balance between making sure something is done to reward DG for reducing peak demand vs. ensuring the reward accurately reflects the actual value provided?
- Where tariffs are clearly not cost reflective (e.g. day/night), is it better to exempt distributors from having to offer rebates linked to these tariffs, or will it help incentivise distributors to make tariffs more cost reflective?
- What is role of VPPs in the long-term (i.e. over and above price-led flexibility)?
- What size limits do distributors tend to place on export already?

Note – this represents preliminary policy thinking only, and does not necessarily reflect EA views

Proposed problem definition

The Task Force said:

"This option would see distributors pay a rebate when consumers export surplus energy back into the system at peak times. While this better rewards consumers who have invested in technologies – such as solar and battery systems – the benefits might be shared to all consumers in the long term through lower lines charges. This is because the electricity is generated locally when and where it's needed, and eases pressure on the local distribution network where it's constrained. This avoids the need for distributors to build more infrastructure to cope with higher demand peaks, meaning lower overall costs, and lower prices for consumers in the long run. This option would further incentivise investment in home solar and battery systems."

Key elements:

- Status quo does **not provide incentive for consumers to invest** in (small-scale) DG that can export at peak times – *solutions should incentivise investment in DG*
- Injecting at peak times **reduces network costs** and leads to lower prices for all consumers in the long run – *solutions should reduce network costs*

Problem definition:

Small-scale DG that injects at peak times is not being routinely and reliably rewarded for the value it provides the distribution network by reducing network constraints and deferring investment in additional network capacity, leading to lower prices for all consumers in the long run.

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Evaluation criteria

What are the impacts of the proposal?

- Does it address the problem(s) identified?
  1. Incentivises investment in DG?
  2. Reduces network costs?
- What potential unintended consequences could result?

How do these impacts affect the Authority's statutory objective?

- Efficient operation of electricity industry
- Reliable supply by electricity industry
- Competition in electricity industry
- Long-term benefit of consumers

Intervention principles

- Principle 1 – Clear case for regulation
- Principle 2 – Costs and benefits are summarised
- Principle 3 – Preference for small-scale 'trial and error' options
- Principle 4 – Preference for greater competition
- Principle 5 – Preference for market solutions
- Principle 6 – Preference for flexibility to allow innovation
- Principle 7 – Preference for non-prescriptive options

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Summary of key design elements

More linked to peak consumption charges

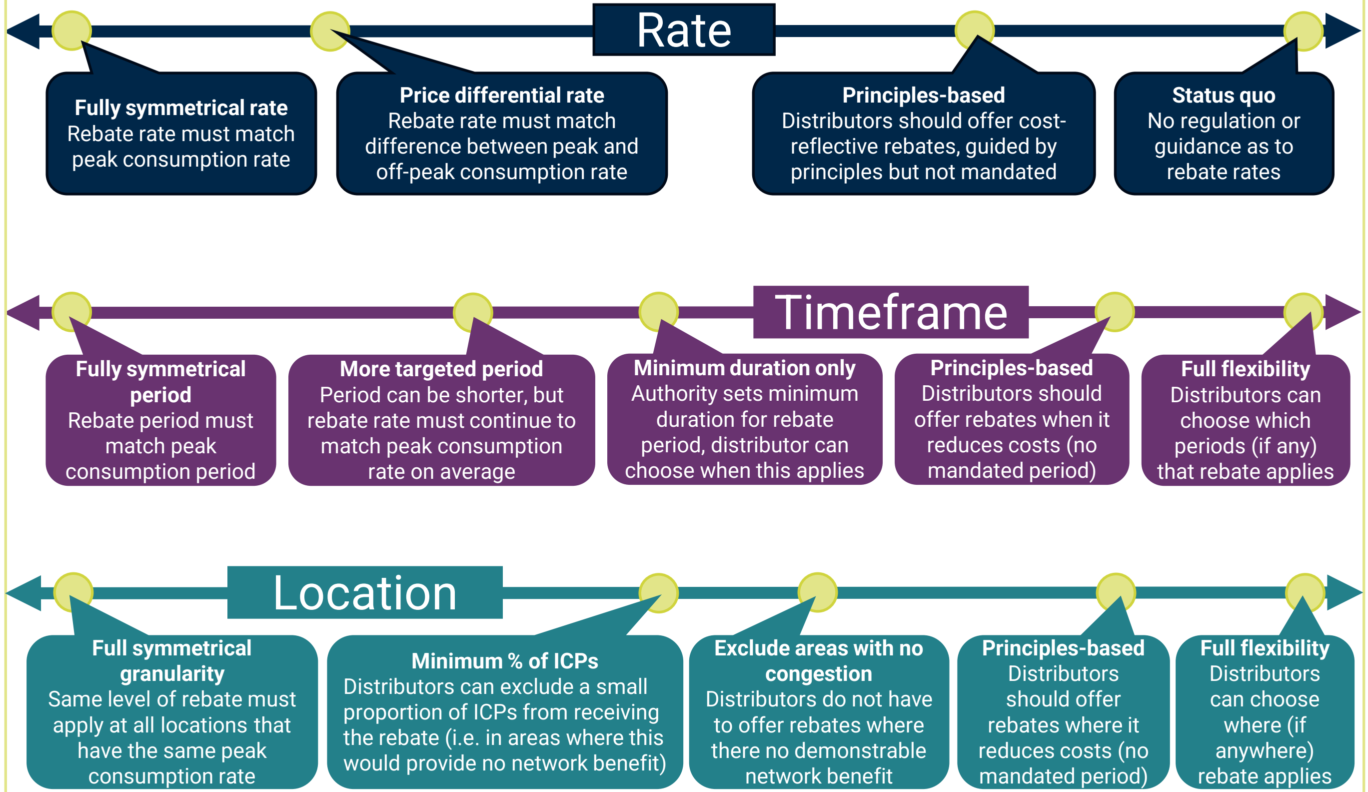
Reduces network costs?

Less accurately rewards export during peaks – peak consumption rate may not reflect true LRMC (e.g. it may be recovering some sunk costs, or reflecting average LRMC over multiple time periods or locations)

Incentivises investment in DG?

Perceived as simple/fair –DG at a specific time or location would be rewarded by the same amount regardless of whether it decreased net consumption or injected into the network. As noted by Essential Energy (an Australian distributor), this "was simple to explain and would be perceived as fair"

Easier implementation – simpler for distributors to implement and the Authority to monitor and enforce, thus ensuring that distributors actually do something to reward DG for providing network benefits



Less linked to peak consumption charges

Reduces network costs?

More accurately rewards export during peaks – allows distributors to set rebates that better reflect LRMC at specific times and locations (to the extent that peak consumption charges do not do so)

Incentivises investment in DG?

Perceived as less simple/fair – price signal for DG may be stronger (or weaker) when it reduces net consumption than when it injects into the network

More complex implementation – distributors may find it difficult to establish a cost-reflective rebate independently of peak consumption charges (so may not implement anything useful at all). To the extent rebates are required to be cost reflective, the Authority would have to assess whether the distributor has done so

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Rebate rate

Design options	Evaluation
1. Fully symmetrical rate Rebate rate must match peak consumption rate	• Most likely to incentivise investment in DG capacity above what is needed to offset consumption during peak times. • Least effective at reducing network costs, as it does not target DG towards specific times and network locations. It relies on peak consumption charges being cost-reflective, which is unlikely to be the case across all distributors, as consumption charges are only regulated by pricing principles, not mandates. • This option would likely be more useful in the future when distribution pricing generally has become more cost-reflective. Recommend this option
2. Price differential rate Rebate rate must match difference between peak and off-peak consumption rate	• Similar to the above, but slightly less likely to incentivise investment in DG capacity above what is needed to offset consumption during peak times. • Slightly more effective at reducing network costs as rebate rate is more likely to reflect true value of peak export. In theory off-peak consumption rates should be at or close to zero anyway (making the price differential the same as the peak consumption rate), but until this is the case, this is likely to a better approach than option 1.
3. Principles-based Reform DG pricing principles so general distribution pricing principles apply to DG. No mandated rebate	• Unlikely to incentivise investment in DG capacity above what is need to offset consumption during peaks, as unlikely to deliver simple and reliable incentives for DG, and implementation likely to be difficult • Provides distributors with flexibility to set DG rewards at a value that best reduces network costs. • Would bring regulation of import and export into alignment (i.e. both would be principles-based, with a focus on cost-reflectivity – see next slide). • Would require Authority to assess EDB performance against principles, which would increase costs for Authority
4. Status quo Existing DG pricing principles apply. No mandated rebate.	• No incentive to invest in DG capacity above what is need to offset consumption during peaks • Distributors cannot set DG rewards at a value that best reduces network costs, as existing DG pricing principles are not appropriate. They do not appear to be implemented in practice for small-scale DG, so this receives no reward for injecting at peak times. They also require DG to be paid the full value of any deferred network upgrades, so this does not actually reduce costs in the long run.

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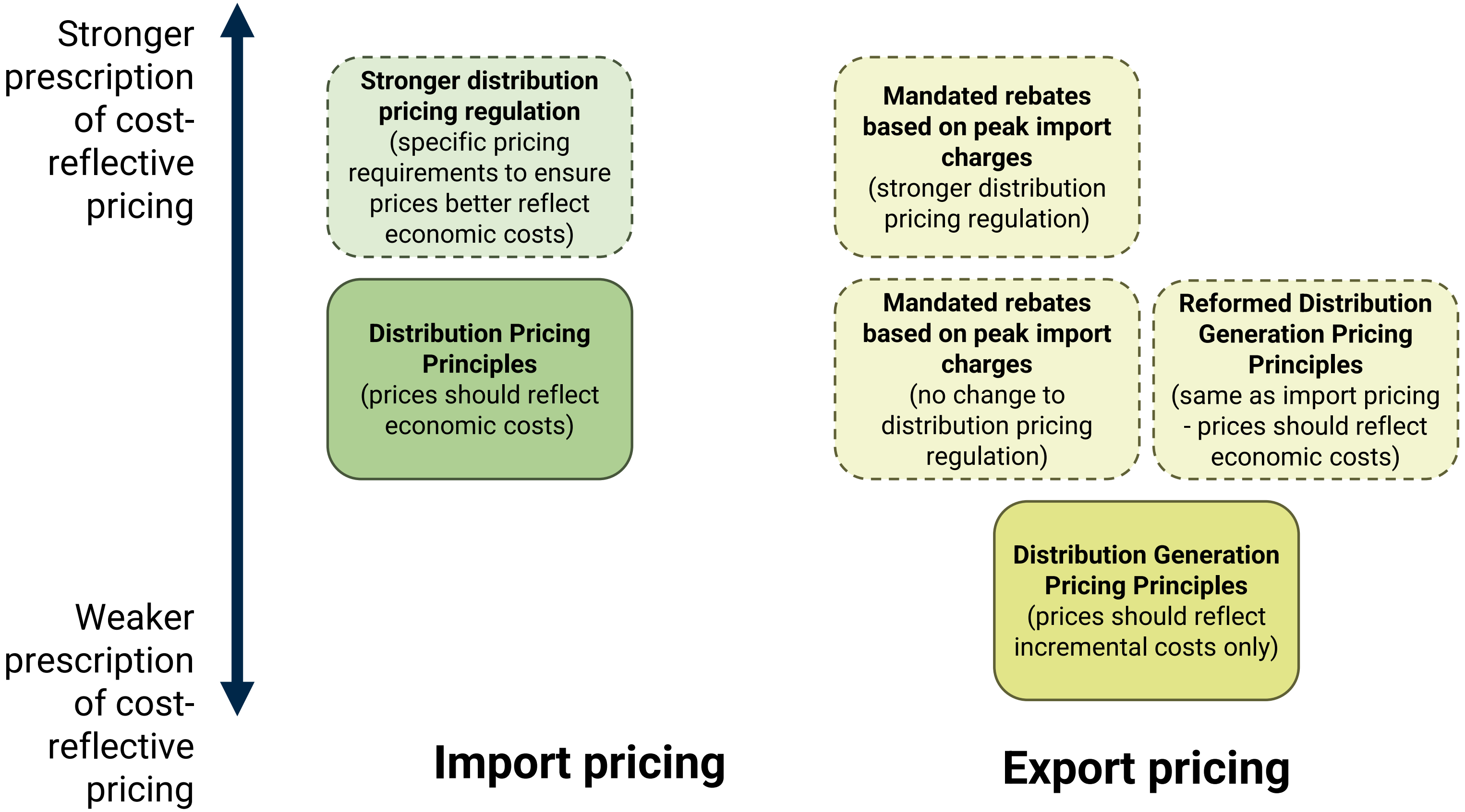
Import pricing vs. export pricing regulation



The DG Pricing Principles (DGPPs) say that DG should only be charged incremental costs, whereas the Distribution Pricing Principles (DPPs) for general distribution pricing say that import pricing should be cost reflective. Neither mandate specific pricing. Therefore:

- if import price regulation remains principles-based, rebates linked to import prices may not be particularly cost-reflective
- reforming the DGPPs to be similar to the DPPs could achieve a similar level of cost-reflectiveness (possibly just as a first step)
- linking rebates to import prices would be more cost reflective with stronger distribution pricing regulation

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Adjustment factors

An adjustment factor could be applied to the rebate rate to reflect the fact that:

- Import rates are not perfectly cost reflective
- Export rebates that are closely tied to import rates are also therefore not perfectly cost reflective
- Under-rewarding export at peak times (on aggregate) may be preferable to substantially over-rewarding export at peak times in some circumstances, because over-rewarding will result in:
  - higher fixed charges in the short term for all customers
  - no reduction in network costs in the long term

South Australia currently has an export rebate that is around 30% of their peak import charge.

We are currently looking at other Australian distributors to determine the level of their export rebates relative to peak charges, and their reasons for this.

Our starting point is no adjustment factor, but we are open minded to reasons why these could be useful

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Rebate period

Design options	Evaluation
Fully symmetrical period Rebate period must match peak consumption period	• Most likely to incentivise investment in DG capacity above what is needed to offset consumption during peak times. • Least effective at reducing network costs, as it relies on peak consumption periods accurately representing times that additional consumption drives network investment. In some cases, peak periods could be quite long (including day/night), which will include times when this is not the case. Recommend this option
More targeted period Distributors can provide higher rebates for a shorter period, so long as the rebate matches the peak consumption charge on average	• Similar to the above. Perhaps slightly less likely to incentivise investment in DG capacity as rebate applies for shorter times, but will be higher to compensate for this. • Slightly more effective at reducing network costs as rebate rate can be more targeted to times where it will help defer network investment.
Minimum duration Authority sets minimum duration for rebate period, distributor can choose when this applies	• Flexible DG is likely to be more responsive to prices than consumption (which is also driven by habit and necessity). Therefore, aligning the export rebate peak with the true consumption peak becomes more important. Where a distributor is aware that network investment is being driven by consumption during a more specific window, they should be able to target the rebate accordingly. This period is unlikely to be fully outside the consumption pricing peak period, but this is a possibility at specific locations (e.g. where the network as a whole has an evening peak, but a certain part of the network, such as an industrial or agricultural area, may have a daytime peak)
Principles-based Distributors should offer rebates when it reduces costs (no mandated period)	• Without a mandated period, distributors may choose to offer rebates rarely (if at all) and for short periods of time, providing limited additional incentive to invest in DG. • Provides distributors with flexibility to set DG rewards at times that best reduce network costs. • Would bring regulation of import and export into alignment (i.e. both would be principles-based, with a focus on cost-reflectivity). • Would require Authority to assess EDB performance against principles, which would increase costs for Authority
Full flexibility Distributors can choose periods when this rebate applies	• Without a mandated period, distributors may choose to offer rebates rarely (if at all) and for short periods of time, providing limited additional incentive to invest in DG. • This option also contains no other guidance or principles to encourage rebates at times where future network costs are reduced.

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Rebate location/granularity

Design options	Evaluation
Fully symmetrical granularity Same rebate must apply at all locations that have the same peak consumption rate	• Most likely to incentivise investment in DG capacity above what is needed to offset consumption during peak times. • Least effective at reducing network costs, as it may not be reflective of true network benefits at specific locations as network charges tend to be smoothed over the entire network. In reality, peak injection at some parts of the network is worth much more than at others. Recommend this option
Minimum percentage of ICPs Distributors can exclude a small proportion of ICPs from receiving the rebate (i.e. in areas where this would provide no network benefit)	• Similar to the above, but allows distributors a small amount of leeway to exclude some ICPs where there are little/no capacity constraints during peak times (i.e. where the rebate would not be reducing network costs). • Maintains steady incentive to invest in spare DG capacity for the majority of the network.
Exclude areas with no congestion Distributors do not have to offer rebates where there no demonstrable network benefit	• Similar to the above, but allows distributors to not offer rebates to ICPs where there are little/no capacity constraints during peak times (even if this is more ICPs than would be allowed under the threshold in the option above).
Principles-based Distributors should offer rebates where it reduces costs (no mandated period)	• Without a mandate to offer rebates at all/most locations, distributors may choose to offer rebates in few locations (if anywhere), providing limited additional incentive to invest in DG. • Provides distributors with flexibility to set DG rewards at locations that best reduce network costs. • Would bring regulation of import and export into alignment (i.e. both would be principles-based, with a focus on cost-reflectivity). • Would require Authority to assess EDB performance against principles, which would increase costs for Authority
Full flexibility Distributors can choose where (if anywhere) rebate applies	• No incentive to invest in DG capacity above what is need to offset consumption during peaks • Without a mandate to offer rebates at all/most locations, distributors may choose to offer rebates in few locations (if anywhere). • This option also contains no other guidance or principles to encourage rebates at locations where future network costs are reduced.

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Other design factors

Design factors	Design options	Effects	Evaluation
Customer type	1. Applies to residential customers only 2. Applies to all mass-market customers (residential and small business) 3. Applies all customers on energy consumption charges (e.g. c/kWh) 4. Applies to all customers, including those on demand charges (e.g. $/KVA)	• Non-residential customers are more likely to have larger-scale DG. If too much DG is incentivised to inject at peak times, it may result in inefficient use of rebates, or even export congestion • Specific Code provisions will be required to achieve same policy intent for customers on tariffs with demand charges	• The same approach should be used to reward DG regardless of what type of customer owns or operates it. Concerns around large-scale DG should be dealt with through a capacity/energy cap instead (see below) • It should not be particularly difficult to implement specific Code provisions for tariffs with demand charges Recommend option 4 (provided they are still limited to tariffs with some kind of peak signal)
LFC customers	1. Rebate applies to all customers 2. Distributors not obliged to provide rebate to LFC customers 3. Distributors not obliged to offer LFC tariffs to customers who may receive the rebate	• LFC customers are likely to have higher variable charges, which may result in the import rate differential (if that method is used) being less cost reflective	• LFC regulations generally make it difficult to provide cost-reflective tariffs. The risk of a consumption charge not being cost-reflective is high, so LFC tariffs should not be offered alongside peak export rebates Recommend option 3 (if feasible), otherwise option 2
Non-TOU tariffs	1. Applies to all customers regardless of their distribution tariff 2. Rebate does not apply to customers on flat tariffs 3. Rebate does not apply to customers on flat tariffs or day/night tariffs	• Completely flat tariffs have no price differential, so does not result in any rebate by default (assuming this method is used for setting rebate rate) • Peak periods of day/night tariffs include the middle of the day, so matching rebate periods will reward export at this time when network benefits are unlikely	• May need other provisions to prevent distributors from increasing the number of their customers on non-TOU tariffs (ties into broader tariff assignment issue) If rebate period must match peak consumption period, recommend option 3. If distributors can set separate rebate periods, recommend option 2. Regardless, should be combined with other provisions preventing tariff reassignment.

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Other design factors (continued)

Design factors	Design options	Effects	Evaluation
ICPs contracted to VPPs	1. Rebate applies to all ICPs 2. Distributors do not have to rebate ICPs that are signed up with an aggregator/VPP that has contracted to provide distribution support	• Where distributors have contracted with an aggregator/VPP to provide distribution support, paying these ICPs a rebate will be rewarding them twice for the same service • If these ICPs are not eligible for rebates (i.e. only rewarded by VPP), then there is risk of disincentivising consumers signing up to VPPs	• Aggregators/VPPs provide more targeted distribution support than a general rebate, so consumers should not be disincentivised from signing up with VPPs • 'Prosumers' with DG that exports at peak should be able to be rewarded for it without having to be part of a VPP • DG should not be rewarded twice for the same export (unless the reward from the rebate is only a small proportion of the value the DG provides) Recommend option 1 (combined with adjustment factor that reduces rebate to below full value of LRMC), based on competition and efficiency factors

Export size limits	1. Rebates are required regardless of size of injection
	2. No rebate is required for injection above a maximum capacity from a single ICP (e.g. 6 kW)
	3. No rebate is required for injection above a maximum amount of energy from a single ICP (e.g. 24kWh a day, 720 kWh a month, etc.)
		• A static rebate could incentivise DG to export even when there is already too much DG exporting into the network, resulting in inefficient use of rebates, or even export congestion
		• A capacity cap limits exports uniformly over time
		• An energy cap only limits the total export over a set period, allowing higher exports at any one time (accompanied by lower exports at other times during the peak period) than an equivalent capacity cap
			• Size limits mitigate over-incentivising export to some degree, although they are an imperfect tool because:
			    • rebates continue to incentivise new ICPs to export even when it is not useful
			    • rebates stop incentivising ICPs from exporting above a certain level even when it would be useful to the network
			• The limit is somewhat arbitrary, but encourages DG to be more evenly spread between multiple consumers
			• Capacity limits are preferable to energy limits, as they encourage more sustained export during peak times
			Recommend option 1, as the distributor may regulate export limits separately already (e.g. for network stability reasons)

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Other design factors (continued)

Design factors	Design options	Effects	Evaluation
Total rebate limit	1. Rebate has no monetary caps 2. Rebate capped (for each ICP) at amount of consumption charges incurred in the relevant billing period (e.g. month) 3. Rebate capped (for each ICP) at amount of consumption charges incurred in the relevant pricing year	• A rebate cap would prevent the distributor from ever having to pay the ICP's retailer – instead, they would reduce the ICP's total charges to a minimum of zero (limiting the total amount of rebates needing to be recovered from other customers) • The shorter the cap period, the tighter the cap (i.e. a yearly cap may allow a month with a net rebate to be rolled over and credited against a month with net charge)	• Rebate caps mitigate over-incentivising export to some degree • The limit is somewhat arbitrary, but encourages DG to be more evenly spread between multiple consumers Recommend option 1, as the distributor may regulate export limits separately already (e.g. for network stability reasons)
Policy duration	1. Distributors must pay rebates indefinitely 2. Rebates become voluntary after fixed period of time (e.g. 5 years) 3. Rebates become voluntary once certain level of DG penetration is met (e.g. 10% of peak consumption)	• An indefinite (or at least a fixed) timeframe for this policy will provide a more reliable revenue stream for consumers considering investing in DG • In time, distributors may develop more accurately cost-reflective ways to reward DG during peaks, after which a simple rebate linked to peak consumption rates may no longer be required • As DG capacity increases as a proportion of peak demand, its value reduces, so distributors should be able to dial back incentives for DG	• A fixed duration of 5 years is likely to provide revenue certainty to encourage an increase in DG investment, without over-incentivising DG. It also gives distributors time to develop more sophisticated mechanisms. Recommend option 1

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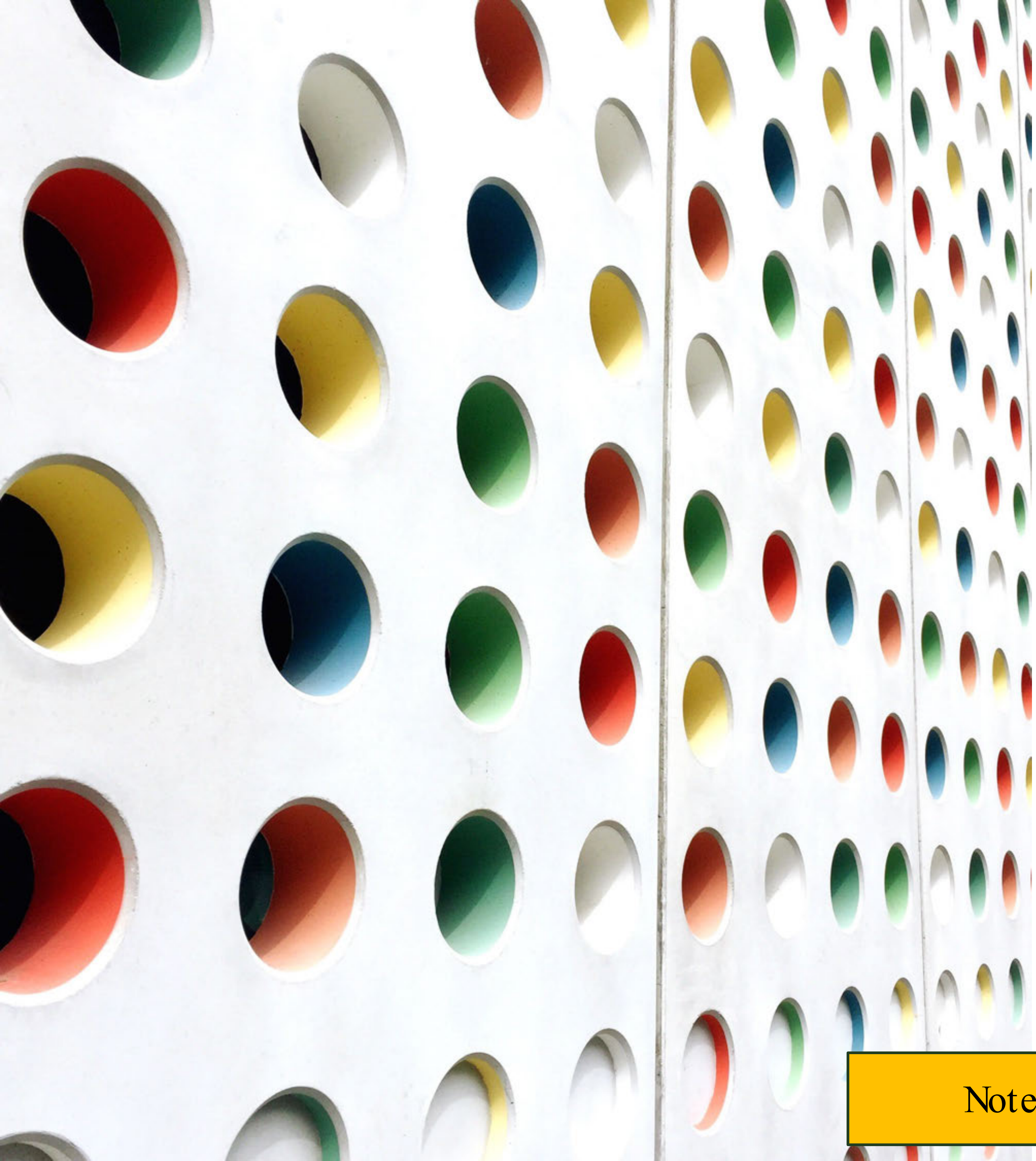


Time varying pricing plans

WORKING VIEWS

Note: Preliminary thinking only – does not represent EA views

Specific questions for EAAG to consider

- What might be driving the variation in offers of time-varying price plans by different retailers?
- What barriers exist to retailers making these plans available to all their customers?
- How significant is the potential for unintended consequences in requiring retailers to offer time-varying price plans
- What can we do / what guidance can we provide to:
  - Maximise the effectiveness of the intervention in realising and sharing genuine cost savings
  - Minimise unintended consequences
- Are there other ways to solve the problem (including any need for speed) that we have not identified?

Note: Preliminary thinking only – does not represent EA views

Preliminary thinking only – does not represent EA views

Time varying pricing plans

WHY

.might we need to do something

WHAT

.might we do about it

HOW

.might we do it

Note: Preliminary thinking only – does not represent EA views

WHY

Problem definition

"Time -of-use pricing allows households to get cheaper electricity by moving their electricity use to off-peak times. Although this is increasingly being offered by retailers, the Task Force will consider making it a requirement for retailers above a certain size to offer their customers. Time-of-use pricing gives households more ability to manage their electricity use and costs. Shifting a significant amount of electricity use to times when it is abundant and cheaper will reduce demand peaks. This means cheaper wholesale electricity costs that can flow through to lower prices for consumers."

Good for consumers

Reduces costs for the market

Competition is delivering, but more to do

Consumers are not being given sufficient incentive or opportunity to shift their consumption to off-peak times, driving higher peak demand and hence system costs than might be efficient

Note: Preliminary thinking only – does not represent EA views

WHY

The potential problems behind the problem

	Some retailers lack visibility of, and don't face the impact of their contribution to peak	Being billed based on profiles Relying on legacy systems
	Retail competition may not be giving enough impetus to innovate in a timely manner	Static switching rates and 'sticky' customers Constrained generation makes for challenging retail environment
	A significant portion of consumers are difficult to engage and have a tendency to leave value on the table	May only provide modest savings and appeal to small subset of consumers Consumers may not realise the potential savings where they are available
	Value of flexibility not transparent or readily traded so may not be allocated efficiently	Gentailers prioritizing generation above seeking out flexible demand-side resources

Note: Preliminary thinking only – does not represent EA views

WHY

Data request to gather evidence

Please list all of the time-varying retail pricing plans that you currently have available to residential customers, by pricing region. For each time-varying retail pricing plan and pricing region, please note:

- the number of residential ICPs that were on each time-varying retail pricing plan as at 31 August 2024
- what, if any, conditions or eligibility criteria apply to each time-varying retail pricing plan (e.g. the plan only being available to customers that own an electric vehicle)
- whether this plan is the default you offer in that pricing region or whether it is only available on request or by exception.

Please answer the same questions above for retail plans that allow the retailer, or another party that is not the distributor, to control the timing of some portion of the customer's load (and in addition please specify the discount that applies for the load control tariff).

What factors have influenced your decision to offer or not offer time-varying retail pricing plans - including where your approach differs by pricing region – and what factors might affect that decision going forward?

Distributors may assign ICPs to TOU distribution tariffs for billing purposes. Where those ICPs have a communicative smart meter, do you have any ongoing difficulties in providing distributors with accurate time-based consumption data (that is, consumption either by individual half hour, or split into time-blocks like peak and off-peak) for billing purposes? If so, what factors are preventing you from providing accurate time-based consumption data for those ICPs, and what may change this going forward? For example, access to data, or billing systems.

Note: Preliminary thinking only – does not represent EA views

MDAG demand-side flex recommendations

- The need to engage greater demand side flexibility a key focus of MDAG's work
- Suggested four relevant developments (in addition to several relating to distribution issues)
  - Activity monitoring (recommendation 3)
    - Regular disclosure of tariffs, uptake, DSF participation, use of profiles
    - Authority (or 3rd party) to collate into 'DSF scorecard' report
    - Intended to assess the degree to which industry is making progress
  - Sunset profiling (recommendation 18)
    - Set a date upon which reconciliation must be done on half-hour data
  - New flexibility products (recommendation 8)
    - Forward price discovery and hedging for flex
  - Improve consumer awareness of demand-side flexibility (recommendation 20)
    - Enable powerswitch to demonstrate value of DSF to consumers
    - Make consumer data for DSF-rewarding tariffs more easily accessible to intermediaries

Note: Preliminary thinking only – does not represent EA views

HOW
...might we do it

Eight high-level options

1		Do nothing
2	a	Prevent aggregation of half-hourly data
	b	Mandate the capability to provide time-varying plans
3		Mandate offering of time-varying pricing plans
4		Mandate offering of load control price plans
5		Mandate offering of time varying OR load control price plans
6		Mandate time-varying plans as the default
7		Improve consumer awareness
8		Monitor price-plan developments

These are not all mutually exclusive, and could package together to form a solution

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option # 1

Do nothing

- No new requirement on retailers to offer tariffs
- Continue to rely on incentives from:
  - retail competition - to drive innovation and efficiency
  - distribution pricing – to improve cost reflectivity

Status quo

Lean on Package 1 changes

To support greater retail competition and efficient use of flexibility

Good points

- Doesn't risk impacting existing competitive retail activity or restricting retailer flexibility to innovate

Bad points

- May take too much time to see results, leading to ongoing peak capacity constraints, high prices, and hence increased costs for consumers

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #2a

Prevent aggregation of half-hourly data

- Likely a pre-requisite / co-requisite of other options
- Require that retailers submit half-hourly data for billing purposes where it exists, rather than having distributors charge them based on profiles
- Part 15 review plans to address this same problem for wholesale reconciliation perspective

Good points

- Doesn't risk impacting existing competitive retail activity or restricting retailer flexibility to innovate
- Would ensure retailers are charged for the actual costs they cause - improved visibility
- Improvements to billing systems may reduce a barrier to introducing more complex tariffs

Bad points

- Retailers will face costs to upgrade systems, which may take some time
- May not sufficiently change incentives to address the problem

Note: Preliminary thinking only – does not represent EA views

High-level option #2b

Mandate the capability to provide time-varying plans

- Require that retailers are capable of offering time-varying plans, but don't require they specifically do so
- Closely related to option #2
- Retail data survey may illuminate other barriers that could allow us to be more specific and targeted as to what this might entail

Good points

- Doesn't risk impacting existing competitive retail activity or restricting retailer flexibility to innovate
- Ensures barriers are removed
- May result in greater innovation in price plans and demand management

Bad points

- Difficult to assess compliance (absent more specifics)
- Retailers will face costs to upgrade systems, which may take some time
- Introduces a compliance burden for EA (difficult to assess capability)

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #3

Mandate offering of time-varying pricing plans

- Require that retailers offer at least one time-varying pricing plan aimed at shifting load

No additional guidance
Introduce requirement but no specifics

Principles-based guidance
Introduce principles for what the plan should be / achieve

Prescriptive guidance
Include specific rules around the structure of the plans

Good points

- Ensures all consumers can access time-varying plans
- May result in more load shifting to off-peak times
- May support greater innovation in price offers – particularly to shift load, but also generally

Bad points

- May undercut existing competitive activity
- May reduce flexibility to innovate on pricing
- May lead to a proliferation of low-quality pricing plans
- Retailers will face costs to upgrade systems, which may take some time
- Introduces a compliance burden for EA (greatest for principles-based, least where no additional guidance provided)

Note: Preliminary thinking only – does not represent EA views

High-level option #4

Mandate offering of load control plans

- Mandate retailers to offer at least one pricing plan that allows for control of key loads
- Could have same sub-options of:
    - No further guidance
    - Principles-based guidance
    - Prescriptive guidance
- Could be in addition to, or instead of previous option.

Good points

- Forces innovation in an important area
- May result in more load shifting to off-peak times
- May support greater innovation in demand management

Bad points

- May undercut existing competitive activity and reduce flexibility to innovate in other ways/areas
- Starting from a low base so costs and timeframes for retailers to develop tech and upgrade systems would be high
- May lead to a proliferation of low-quality pricing plans
- Introduces a compliance burden for EA - (greatest for principles-based, least where no additional guidance provided)

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option # 5

Mandate offering of price-varying or load control price plans

- Mandate retailers to offer at least one plan that is either time-varying or allows for control of key loads
- A variation of the previous two options

Good points

- Allows retailers more flexibility to innovate around consumer demand management

Bad points

- Reduces pace of change as load control price plans are likely to require more, and more costy development
- Plans may be complementary, rather than substitutes, hence has potential to miss significant value in other ways/areas
- Other costs/risks consistent with previous two options

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #6

Mandate time-varying plans as the default

- Make time varying plans the default offer for all residential consumers
- Would be similar to, or equivalently achieved by requiring distribution price pass-throughs

Good points

- Sends clear price signals to all consumers
- May result in more load shifting to off-peak times
- May support greater innovation in demand management
- Quick results as not dependent on switching rates

Bad points

- May undercut existing competitive activity
- May penalise consumers that are least likely or able to respond to the signal, with social consequences
- May lead to a proliferation of low-quality pricing plans
- Introduces a compliance burden for EA

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #7

Improve consumer awareness of value of load shifting

- As per MDAG recommendation 20
- Facilitate data access for consumers and intermediaries to make price-plan (incl TOU) comparisons easier
- Develop Powerswitch to capture / illuminate benefits of load shifting

Good points

- Could increase switching, including amongst stickier customers, which could lead to increased uptake of time-varying pricing plans, leading to better demand management
- Could have wider benefits for competition, and the innovation it can support
- Could complement other options

Bad points

- Data access may have privacy and ownership issues to consider
- Has implementation costs for the EA and Powerswitch

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #8

Monitor price-plan developments

- As per MDAG recommendation 3
- Could comprise compliance assessment under other options
- Regular reporting of an 'industry scorecard' to assess the degree to which the industry is providing options to incentivise consumers to shift/reduce load
- Draw on data from retail data survey
- Could include self-reporting

Good points

- Sends clear signal that development is expected
- May drive development as highlighting relative performance could encourage competitive tension, resulting in improved demand management
- Supports compliance assessment of other options

Bad points

- May not materially alter incentives to improve, resulting in no improvement in demand management
- Introduces a compliance burden for EA (and participants if self-reporting)

Note: Preliminary thinking only – does not represent EA views

HOW

…might we do it

Design details to work through

What pricing guidance we provide (next slide for more details)	• Prescription vs principles vs nothing	
Exemptions we might apply	• Minimum retailer size o ICP count, market share • Retailers without generation (lower incentives to manage demand) • Customers without smart meters (for practical reasons)	• LFC customers? (may be too complex to price for and ensure cost recovery) • Non-residential consumers (not main drivers of peak demand)

What constitutes 'offering' something (subsequent slide for more details)	• List on website
	• List on powerswitch
	• Offer if asked
		• Make a pro-active offer
		  o To all / to some
		  o One time / periodically
		  o Include savings calc / best plan

Phase out / review requirements	• Fixed term (rely on inertia to maintain, regain full flexibility) • Align with other changes • Review in X years	
How to assess compliance / performance	• Regular Authority reviews (of price structures, uptake rates, peak demand impacts, customer impacts)	• Self-reporting (like distribution PP) • Audit or independent review

Note: Preliminary thinking only – does not represent EA views

HOW
…might we do it

Example of prescriptive pricing guidance

- *Minimum duration of peak and off-peak periods:*
  - *linked to distribution tariffs (length only / length and times / minimum proportion of length)*
  - *set time (e.g. 3 hours) – needs to be enough for consumers to be able to shift their load.*
  - *would something like "hour of power" qualify?*
- *Minimum price differential*
  - *at least as big as price differential in distribution TOU tariff (i.e. to ensure this gets passed through)*
  - *plus a wholesale price component (but harder to quantify, and likely to change over time)*
  - *tie to minimum duration (e.g. short periods require large differentials)*

Note: Preliminary thinking only – does not represent EA views

Example of principled pricing guidance

- *Prices are to signal the economic costs of consumption, including by:*
  - *reflecting the relative economic costs of network use during peak and off-peak times;*
  - *reflecting the relative economic costs of generation use during peak and off-peak times; and*
  - *encouraging efficient demand-side alternatives.*
- *Development and application of prices should have regard to:*
  - *transaction costs, consumer impacts and uptake incentives*
  - *the potential to create a secondary peak*
  - *new technologies that have the potential to materially impact peak demand (such as EVs)*

Modified from distribution pricing principles

Address key peak demand concerns

Note: Preliminary thinking only – does not represent EA views

There is the potential for unintended consequences in this space

- Undercutting existing competitive activity
  - Retailers are busy innovating in this space
  - This includes independent retailers who have made TOU or load-control price plans a key point of difference – which has been subsequently replicated (to a degree) by larger retailers
  - A mandatory requirement may crowd out these smaller players, reducing their ability to compete, and hence reducing the competitive discipline they have provided on others

- Introducing rigidity into a fast-moving environment – reducing responsiveness
  - With increasing renewables, definition of a 'peak' could very like change (generation slump rather than demand peak)
  - Increasing flexible demand resources – few new flexible generation sources
  - Time varying pricing relatively novel – trial and error required to figure out how to attract customers and target niches
  - LUFC experience – significant inertia to regulated tariff options

- Creating a secondary peak

- Adding confusion to a 'busy' price plan environment that becomes counterproductive
  - Finding ways to cut through may be a necessary co-requisite (eg Powerswitch development, data access etc)

Note: Preliminary thinking only – does not represent EA views

WHAT

Evaluation criteria

- What are the impacts of the proposal?
  - Does it address the problem(s) identified?
  - What potential unintended consequences could result?
- How do these impacts affect the Authority's statutory objective?
  - Efficient operation of electricity industry
  - Reliable supply by electricity industry
  - Competition in electricity industry
  - Protect interests of small consumers
- Intervention principles – speak to potential for unintended consequences
  - Principle 3 – Preference for small-scale 'trial and error' options
  - Principle 4 – Preference for greater competition
  - Principle 5 – Preference for market solutions
  - Principle 6 – Preference for flexibility to allow innovation
  - Principle 7 – Preference for non-prescriptive options

Note: Preliminary thinking only – does not represent EA views

Evaluation

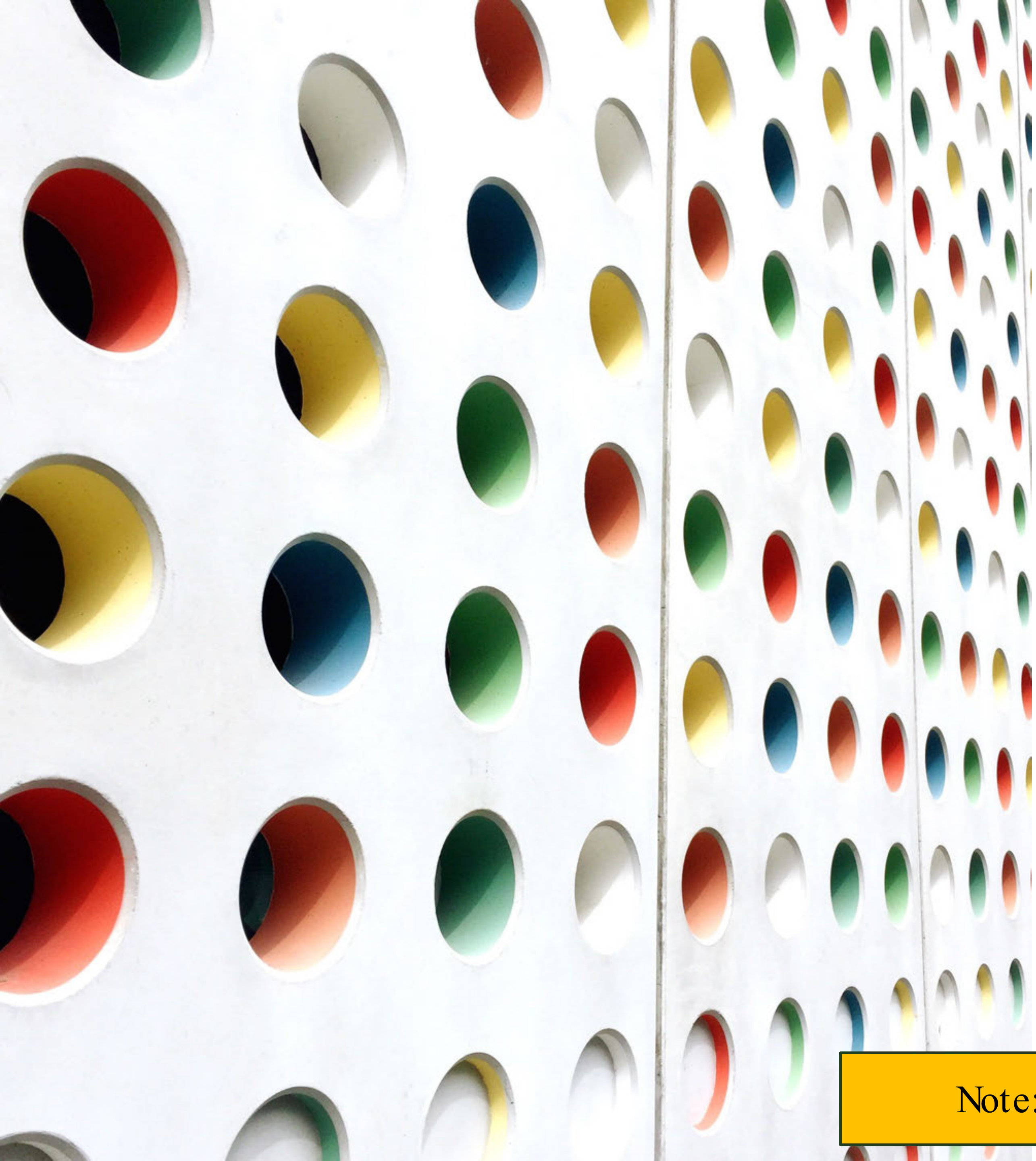
Overall negative

Net neutral or no impact

Overall positive

Note: Preliminary thinking only – does not represent EA views

			Solves problem	Statutory objective				Unintended consequences					Explanation / comment
				Competition	Reliability	Efficiency	Consumer interests	Small-scale	Greater competition	Market solutions	flexibility	Non-prescriptive	
1	Do nothing	At all											Doesn't solve the problem
		Package 1											Could improve retail competition, which may drive improvement in this area over time
2a	Prevent data aggregation												Likely addresses part of the problem, with some costs but an overall improvement in efficiency – a low regrets option
2b	Mandate TOU capability												Likely addresses part of the problem, but may not materially alter incentives to offer, and hence may introduce costs that are not justified by any offsetting benefit
3	Mandate TOU offers	No guidance											May address the problem and is a lesser intervention with a low compliance burden, but may also be counter-productive by creating a proliferation of low-quality tariffs that add cost/complexity with little offsetting consumer benefit
		Principles											Likely to address the problem and create focussed competition that leads to reduced peak demand. However, competition benefits may be offset by undercutting existing competitive activity, with some reduction in flexibility to innovate. Efficiency benefits offset by greater compliance burden on the authority than more definitive approaches
		Prescriptive											May address the problem and lead to reduced peak demand if the prescriptive plan has consumer appeal. However, low diversification of plans may mean no competition benefits while also undercutting existing competitive activity, and materially reducing flexibility to innovate
4	Mandate load control price plans												Addresses a similar problem and creates focussed competition. However, starting from a low base, so costs are likely to be high and may offset any efficiency benefits, while also undercutting existing competitive activity. A more significant intervention..
	Mandate price-varying or load control price plans												May address the problem, but the different approaches are complements rather than substitutes, so may leave part of the problem unsolved. May also delay a response as where load-control is preferred, development could be slower and more costly. Shares other costs/risks with both options.
5	Mandate default TOU												Addresses the problem and likely to create focussed competition, but likely to negatively impact consumers that are not well positioned to respond. A significant intervention..
6	Consumer awareness												Improves awareness of savings available and drive switching to where existing retail activity is providing value. Avoids negative retail impacts, and incentivises innovation, but may take time to drive change in the



Retail export plans

WORKING VIEWS

Note: Preliminary thinking only – does not represent EA views

Specific questions for EAAG to consider

- What might be driving the variation in solar offers by different retailers?
- How significant is the potential for unintended consequences from these options
- What can we do / what guidance can we provide to:
    - Maximise the effectiveness of the intervention in ensuring fair value for exports
    - Minimise unintended consequences
- What should the role of Multiple Trading Relationships be?
- Are there other ways to solve the problem that we have not identified?

Note: Preliminary thinking only – does not represent EA views

Time varying pricing plans

WHY

.might we need to do something

WHAT

.might we do about it

HOW

.might we do it

Note: Preliminary thinking only – does not represent EA views

WHY

Problem definition

"This option would better reward consumers who can provide energy back into the system – most commonly through rooftop solar and batteries – at peak times. Currently many of the rates retailers offer to buy back energy from these households don't reflect the value of that electricity at the time. This option may encourage more people to invest in solar and batteries, as well as reduce electricity bills for all consumers over time if it reduces the cost of peaking generation."

Export rates at peak times appear low

Time-varying export rates could encourage more efficient investment

Existing feed in tariffs offered by retailers do not reflect the value of the energy provided by distributed generation at peak times, which may be discouraging efficient investment.

Note: Preliminary thinking only – does not represent EA views

WHY

Problem is not clear cut

- A range of export rates currently provided by retailers
- Not unreasonable for DG to be offered a hedged price for exports (ie, FPVV)
- Many solar-only owners are likely to:
  - only have excess to export during the middle of the day in summer – when prices tend to be low
  - be net-consumers
  - be very low-users
  - have a peaky, winter-heavy residual consumption profile
- Solar-only owners may hence be more expensive to serve per kWh of consumption than a typical consumer without solar
- This may get reflected in a low export rate, rather than a higher consumption rate
- Important to consider the value of the customer as a whole, or we risk impacting pricing for a much broader group

Bottoming this out is a focus of our analysis and research

Note: Preliminary thinking only – does not represent EA views

WHY

The potential problems behind the problem

Lack of Multiple Trading Relationships

Consumers can't unbundle import and export to maximise value of both

Lack of competition in the retail market

Being a retailer for a customer with solar is equivalent to firming a solar product, and few retailers can do that with confidence

Retailers place low value on consumers with solar

It can be difficult to recover costs through a consumption charge from low user customers

Retailers place low value on distributed generation

They may preference their own generation

Note: Preliminary thinking only – does not represent EA views

WHY

Data request to gather evidence

"Please list all of the retail pricing plans that you currently have available to residential customers that provide a financial reward for power exported to the network. For each of these plans, and for each pricing region (if these plans vary by pricing region), please provide:

- The rate paid for power exported to the network
- The rate (or rates) paid for consumption – including fixed and variable rates
- Any conditions on which the export rate applies, for example, technology type, eligibility criteria, or minimum terms
- The date when each plan was made available
- The individual number of residential ICPs that are on each plan that rewards export as at 31 August 2024

What factors did you consider when setting your export rate? Does the export rate relate to/depend on the consumption rate, and if so, how?

How do you expect your export plans (including rates, conditions, availability, etc.) to change in the future?"

Note: Preliminary thinking only – does not represent EA views

High-level option # 1

Do nothing

- No required changes to what retailers pay for electricity exports from small-scale distributed generation

Status quo

Lean on Package 1 changes

To support greater retail competition and access to flexibility for firming

Good points

- Doesn't risk impacting existing competitive retail activity

Bad points

- May not solve the problem, or take too long time to see results from retail competition
- Doesn't provide any additional incentive to consumers in the near term
- Status quo perceived as unfair

Note: Preliminary thinking only – does not represent EA views

High-level option #2

Mandate spot-based export rates

- Require that retailers offer price plans that reward exports at the real-time wholesale price
- At least one retailer known to do this currently

Good points

- All retailers would provide a precise reward of the value of DG at the time of injection
- Same rate could apply to all generation technologies

Bad points

- Provides volatile signal that may not incentivise investment in DG
- Need to prevent battery cycling when fixed consumption rate < dynamic export rate (charging & discharging without providing any system value)
- Retailers will face costs to upgrade billing systems, which may take some time
- Introduces inflexibility in price plan design, and may undercut existing competitive activity
- Introduces a compliance burden on EA

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #3

Mandate minimum export rates for specific peak periods

- Retailers must offer a prescribed minimum export rate during peak demand periods

Based on ASX futures price
Tie export rates to the ASXforward price curve

Based on historic price
Tie export rates to historic prices

Based on consumption rate
Tie export rates to the consumption rate

Good points

- All retailers would reward and incentivise flexible DG that can contribute during high-value periods
- Same tariff could apply to all generation technologies
- Competition can continue around anytime-rates

Bad points

- Does not improve incentives for DG generally, so will have less impact on periods of energy scarcity
- May lead to lower export rates at other times / higher consumption rates if prescribed rate does not reflect total customer value
- Not a clear peak price signal to draw on (ie ASX)
- Introduces inflexibility in price plan design, and may undercut existing competitive activity
- Retailers will face costs to upgrade systems, which may take some time
- Introduces a compliance burden for EA

Note: Preliminary thinking only – does not represent EA views

High-level option #4

Mandate minimum export rates at all times

- Retailers must offer a prescribed minimum export rate at all times
- Could be combined with option 3

Based on ASX futures price

Tie export rates to the ASX forward price curve

Based on historic price

Tie export rates to historic prices

Based on consumption rate

Tie export rates to the consumption rate

Good points

- All retailers would reward and incentivise DG generally, at a transparent rate
- Simple offer, which retailers could readily implement

Bad points

- Risks encouraging more DG than is efficient, leading to solar saturation and network congestion
- Likely requires different rates for different technologies (based on % of average price each technology likely to 'capture')
- May just be offset by higher consumption rates if export rate does not reflect total value of customer
- Introduces inflexibility in price plan design, and may undercut existing competitive activity
- Introduces a compliance burden for EA

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #5

Mandate minimum export rates during extreme shortages

- Retailers required to offer a minimum export rate during specified shortage events
- Could be combined with other minimums under option 3 and 4

Good points

- All retailers would reward and incentivise DG when it is particularly valuable
- Could maintain retailer flexibility to set export rates for other times, and compete around DG price plans

Bad points

- Not a reliable income stream on which to base DG investments
- Shortage events hard to define – can have high prices without triggering any risk measures (eg August 2024)

Note: Preliminary thinking only – does not represent EA views

WHAT

High-level option #6

Mandate offering of export plans without setting minimums

- Require that retailers offer at least one export plan

No additional guidance
Introduce requirement but no specifics

Principles-based guidance
Introduce principles for what the plan should be / achieve

Prescriptive guidance
Include specific rules around the structure or nature of the plans

Good points

- Would lead to more and more diverse pricing plans with export rates
- Maintains some flexibility to set export rates, and compete around DG price plans (depending on level of guidance provided)

Bad points

- May undercut existing competitive activity
- May still systemically under-reward distributed generation, if it is not being fairly valued by retailers
- May lead to a proliferation of export rates that consumers find confusing
- Introduces some inflexibility in the approach
- Introduces a compliance burden for EA (greatest for principles-based, least where no additional guidance provided)

Note: Preliminary thinking only – does not represent EA views

HOW

…might we do it

Design details to work through

What pricing guidance we provide (next slide for more details)	• Prescription vs principles vs nothing
How to set any minimum price (next slides)	• Based on ASX, historic prices, consumption rates – or something else • Adjustment factors
Interaction with distribution rebate (2A)	• Could include pass-through of a distribution rebate – including if it were negative
Exemptions / exclusions we might apply	• Minimum retailer size (ICP count, market share) • Retailers without generation
Limits we might apply	• Maximum DG size (eg. 10 kW) • Injects more than a set amount in some period (eg 10 kWh/h) • Annual injection > annual consumption
Which price plans does it apply to?	• All of a retailer's plans • At least one plan • DG-exclusive plans
Phase out / review requirements	• Fixed term (rely on inertia to maintain, regain full flexibility) • Align with other changes (eg Multiple trading relationships) • Review in X years
How to assess compliance	• Regular Authority reviews (of price plans) • [illegible] review

Note: Preliminary thinking only – does not represent EA views

Basis for minimum price & adjustment factors

ASX

- Forward looking – reflects expected value
- Clear transparent price
- But needs adjustment to:
  - reflect weighted avg price of DG at time of export (generation net of consumption) consistent with each specific option (eg peak / anytime).
  - Location adjustment?
- And decisions around what product, how far ahead, what timeframe, what location, update period etc

Historic

- Backwards looking – so may not capture fundamental changes in prices (like now) – risks over/under-rewarding for a time
- Easy to understand
- But needs adjustment to :
  - reflect weighted avg price of DG at time of export (generation net of consumption) consistent with each specific option (eg peak / anytime).
- And decisions around historic period to average, annual / quarterly / peak etc, location, update period etc

Consumption rates

- Reflects value of energy to retailer
  - Makes export value consistent with avoided cost of consumption
- Easy to understand
- But needs adjustment to :
  - variable charge recovers some transmission and distribution costs, hedging, levies and cost-to-serve (including retail margin)
- May need adjustment if export structure different from consumption structure (ie, TOU vs flat)

Note: Preliminary thinking only – does not represent EA views

WHAT

Principled pricing guidance examples

- Prices are to signal the economic value of distributed energy resources, including by:
  - reflecting the economic value of energy to the retailer at different times
  - reflecting any avoided network costs recognized by the distributor
  - reflecting economic costs to the retailer/aggregator from buying the distributed energy
- Development of prices should have regard to transaction costs, consumer impacts and uptake incentives.
- Prices should not prejudice or advantage any individual technology

Note: Preliminary thinking only – does not represent EA views

WHAT

Evaluation criteria

- What are the impacts of the proposal?
  - Does it address the problem(s) identified?
  - What potential unintended consequences could result?
- How do these impacts affect the Authority's statutory objective?
  - Efficient operation of electricity industry
  - Reliable supply by electricity industry
  - Competition in electricity industry
  - Protect interests of small consumers
- Intervention principles – speak to potential for unintended consequences
  - Principle 3 – Preference for small-scale 'trial and error' options
  - Principle 4 – Preference for greater competition
  - Principle 5 – Preference for market solutions
  - Principle 6 – Preference for flexibility to allow innovation
  - Principle 7 – Preference for non-prescriptive options

Note: Preliminary thinking only – does not represent EA views

WHAT

Evaluation

- Overall negative
- Neutral or no impact
- Overall positive

			Solves problem	Statutory objective				Unintended consequences					Explanation / comment
				Competition	Reliability	Efficiency	Consumer interests	Small-scale	Greater competition	Market solutions	flexibility	Non-prescriptive	
1	Do nothing	Status quo											Doesn't solve the problem
		Package 1											Could improve retail competition and ability to access firming, which may drive improvement in this area over time
2	Mandate spot-based rates												Provides a fair reward but may be too volatile to incentivise DG investment so may only partially address the problem. Could improve competition around export plans, but may undercut existing competitive activity and reduce flexibility in price design. Risks impacting prices more broadly (ie consumption rates).
3	Mandate min peak rates												Likely to incentivise greater uptake of batteries. Could improve competition around export plans, but may undercut existing competitive activity and reduces flexibility in price design. Risks impacting prices more broadly (ie consumption rates).
4	Mandate min anytime rates												May incentivise greater uptake of solar. Would improve competition around export plans, but may undercut existing competitive activity and reduce flexibility in price design. Risks impacting prices more broadly (ie consumption rates).
5	Mandate min shortage rates												Improves the reward for DG during periods of scarcity. Unlikely to provide a return that would incentivise investment but may influence operation. Could complement existing rules that apply during conservation campaigns and other scarcity events.
6	Mandate offering of plans but not minimum rates												Could address the problem by ensuring key points of differentiation are recognised while maintaining some flexibility in the approach. Could undercut existing competitive activity, and risks impacting prices more broadly (ie consumption rates)

Note: Preliminary thinking only – does not represent EA views

From: [redacted]
To: Carl Billington; EAAG
Cc: Jamie
Subject: Notes on tariff options discussed yesterday
Date: Thursday, 24 October 2024 7:19:17 am
Attachments: image001.png
2A essay plan - revised.pptx
2B essay plan - revised.pptx
2C essay plan.pptx

Morning,

Thought I would flick these through now before I forget – my thoughts captured in comments within the attachment. Apologies if the comments are unclear at all – let me know and I can try work out what I was thinking.

Thanks

[redacted]

Proposals to encourage efficient investment in distributed generation

Electricity Authority Advisory Group: subgroup 1 meeting 1

Attendees:	EAAG	Electricity Authority
	Jamie Silk	Harpreet Singh
	James Tipping	Campbell Garrett
	Deborah Hart	Louise Grace-Pickering
	Fiona Wiseman	Tim Sparks
	Jason Larkin	Kirsty Hutchison
	Ryno Verster	
	Huia Burt	

1. Meeting objective

1.1. We have further developed the proposals we discussed with the Advisory Group on 28 August. We are considering some more specific policy questions about how we will design the proposals, mitigate any risks, and make sure they benefit consumers.

1.2. We are looking for your views on the specific questions in this briefing during the meeting. We would also appreciate any feedback you would like to provide beforehand.

2. Background

2.1. As part of a package of work related to creating market conditions for fair compensation, we are considering a set of four proposals. These seek to improve options for electricity consumers to ensure the right incentives to encourage efficient investment in distributed generation.

2.2. These proposals are now being led by the Energy Competition Task Force; jointly established by the Electricity Authority and Commerce Commission to investigate ways to improve the performance of the electricity market. The Task Force's work programme focuses on two overarching outcomes:

(a) enabling new generators and independent retailers to enter, and better compete in the market

(b) providing more options for end-users of electricity.

2.3. These outcomes will encourage more and faster investment in new electricity generation, boost competition, enable homes, businesses and industrials to better manage their own electricity use and costs, and put downward pressure on prices.

2.4. The Task Force is considering new initiatives and some that are already underway but can be accelerated so New Zealanders can benefit from a better performing electricity system sooner.

2.5. *Task Force Package 2 – Provide more options for end-users of electricity.* Options being considered include:

(a) Requiring distributors to pay a rebate when consumers export electricity at peak times

(b) Requiring retailers to better reward consumers for supplying power

(c) Requiring all retailers to offer time-of-use pricing

(d) Rewarding industrial consumers for providing short-term demand flexibility

2.6. We're seeking input, feedback, and policy design assistance from the Advisory Group on options (a) and (b) of the Task Force Package 2.

3. Recap on the proposals

3.1. Requiring distributors to pay a rebate when consumers export electricity at peak times

3.2. This option would see distributors pay a rebate when consumers export surplus energy back into the system at peak times. While this better reward consumers who have invested in technologies like solar and battery systems, the benefits might be shared to all consumers in the long term through lower lines charges.

3.3. This is because the electricity is generated locally when and where it's needed, and eases pressure on the local distribution network where it's constrained. This avoids the need for distributors to build more infrastructure to cope with higher demand peaks, meaning lower overall costs, and lower prices for consumers in the long run. This option would further incentivise investment in home solar and battery systems.

3.4. This could be achieved by setting a Code requirement (or pricing principle) for distributors regarding pricing for injection during peak periods. The Code requirement could require a tariff component with a negative rate for injection, identical to the tariff rate for peak consumption (as Rewiring Aotearoa has proposed) or set at some proportion of the consumption peak rate, eg, 50 percent.

3.5. The proposal is designed to be applied to small-scale generation, eg, residential battery storage. It provides a financial incentive that could encourage households to invest in battery storage alongside rooftop solar. This could help to address the energy shortage, improve security of supply and ultimately lower electricity prices.

3.6. Requiring retailers to better reward consumers for supplying power

3.7. This option would better reward consumers who can provide energy back into the system at peak times, usually through rooftop solar and batteries. Currently, many of the buyback rates retailers offer don't reflect the value of that electricity at the time it is supplied.

3.8. This option may encourage more people to invest in solar and batteries and reduce electricity bills for all consumers over time if it reduces the cost of peaking generation.

3.9. This could be achieved by setting a Code requirement for retailers to offer a pricing plan for exported generation aligned to either:

(a) the spot price (for example, buyback prices must be at least 80 percent of the spot price)

(b) import prices (for example, buyback prices must be at least 80 percent of the import rate)

3.10. At this stage, we'd prefer to make it mandatory for retailers to offer either of the above options for each import plan they offer.

4. What alternative options should the Authority consider?

4.1. In future, consumers will have more control and more agency over their energy use. We need regulation that both enables participation and rewards people for reducing pressure on the system and contributing to New Zealand's security of supply.

4.2. The main objective of these two proposals is to reward customers fairly for the system value created by distributed generation. These proposals are designed to increase uptake of distributed generation to contribute to New Zealand's overall energy mix. This will reduce the shortages we have experienced in 2024 and avoid the need for more costly distribution investment to cope with higher peaks. We are trying to ensure lower prices for consumers in the long run.

4.3. We're interested in your views on alternative options that could achieve the same outcomes with less intervention from us.

5. We need more information about distributors' views of constraints, herding, and congestion on the low voltage network

5.1. We are considering issues around incentives for distribution generation and its use to avoid network investment. We are interested in your views on the extent to which distributed generation can help avoid investment. Specifically, we seek your feedback on the following questions:

(a) To what extent can non-dispatchable distributed generation help avoid network investment? Our preliminary view is that only dispatchable distributed generation avoids network investment.

(b) To what extent do distributors have visibility of constraints in the low-voltage network?

(c) Do distributors have visibility of herding behaviour? Herding behaviour is the possibility of DER responding to price signals without incorporating distribution constraints. This is a greater risk in parts of the network with relatively few customers per transformers as export is more likely to be coincident.[1]

(d) To what extent do distributors expect export congestion in the future?

  (i) What would be the timeline before export congestion requires additional investment?

(e) Does the Part 6 incremental cost limit cause problems in rewarding distributed generation for reducing costs?

(f) Does the Part 6 ACOD requirement cause problems in rewarding distributed generation for reducing costs?

  (i) Are there any significant differences between small-scale distributed generation and larger distributed generation in terms of the problem?

6. We have identified potential issues with both proposals which will need to be addressed in policy design

6.1. We are looking for input from the subgroup on the policy design issues we have identified, as well as feedback on any potential policy design issues that we have not listed. This includes technical suggestions, or any concerns based on your roles and experience around how retailers or distributors would implement the proposals.

6.2. The main issues and policy design questions we expect could arise from both proposal **(a)** and **(b)** are:

(a) ***Export congestion and herding***, where multiple consumers in an area may follow the same price signals at similar times, resulting in export congestion on localised parts of the network.

(b) ***Distributional impacts and equity concerns***. These proposals will result in the greatest benefits to consumers with the ability to meet the upfront costs of distributed generation, and may initially result in additional costs to consumers without that ability.

(c) ***Targeting residential ICPs.*** We are considering whether to apply each of the proposals to all ICPs, or to only mandate the proposals for residential ICPs

(d) ***Setting an energy and a capacity limit***. We are considering whether to only require rebates and specific export pricing for distributed generation under a certain capacity (eg, 10kW), and for a certain amount of energy per day (eg, 25kWh).

(e) ***Low Fixed Charge Tariff overlap***. The LFC regulations are currently being phased out through 2027. We are considering how to ensure there are no unintended overlaps between these proposals and the LFC regulations.

[1] See MDAG recommendation 19 “Network capacity in DSF dispatch” for more details

(f) ***Whether to make changes permanent or temporary***. For the retail proposal, we are considering whether the mandated buyback price plans should be reviewed after three years, to ensure consumers see benefits while also providing some clarity to industry about the intended approach to extending or ending the policy.

6.3. The main issues and policy design questions that may arise from proposal **(a) requiring distributors to pay a rebate when consumers export electricity at peak times** are:

(a) Interaction with the Commission's Part 4 regulation

(b) Interaction with Part 6 of the Code (DG pricing principles)

6.4. The main issues and policy design questions that may arise from proposal **(b) requiring retailers to better reward consumers for supplying power** are:

(a) ***Battery cycling issues*** (for spot price-linked pricing only), where consumers may be incentivised to repeatedly charge their battery using fixed-price power, and export at a higher wholesale rate. This could worsen energy and capacity issues and raise costs for the retailer.

(b) ***Implementation issues for smaller retailers***. We're considering whether to only mandate larger retailers to avoid unduly burdening smaller retailers. We're currently considering thresholds of one or five percent of residential ICP market share.

(c) ***Issues with pre-pay plans***. We're considering whether pre-pay plans should be exempt from requirements to offer a mandated buyback price plan. This is because of potential issues with the meters used for pre-pay, which may not work for import-export consumers.

(d) ***Designing to ensure we don't stifle innovation***. Mandating specific pricing options for retailers may inadvertently lessen competition for innovative and new products. We want to make sure innovative offerings are still available.

(e) ***Impacts on fixed daily charges***. There is a risk that increases to consumer compensation through higher buyback rates may be cancelled out by commensurate increases to daily fixed charges for consumers with distributed generation. We will need to design the proposal to ensure this doesn't happen.

Symmetrical Export Tariffs[1]

Unlocking a more secure and affordable electricity system

Competitive electricity markets rely on efficient pricing signals to make sure investors are making economically efficient decisions. Current network pricing signals congestion in one direction only, as a high charge on consumption (peak pricing). However, technological progress in solar and batteries now enables a customer (home, farm, business) to not only reduce consumption, but become net-generators at peak time – reducing congestion on the network. This could be thought of as one home with a battery effectively reducing their neighbour's peak consumption.

Yet, typical pricing approaches used by distribution companies in New Zealand do not reward peak battery export. The absence of this signal is not only a loss of market efficiency, it's compromising New Zealand's delivery of a secure and affordable power system in multiple ways:

1. New Zealand's ability to maintain security during winter peak demand is falling behind peak demand growth.

2. New Zealand is on track to spend tens of billions on expanding network infrastructure in response to anticipated increases in peak demand.

3. The lack of signal is stifling demand-side battery investment by not accurately reflecting the value of those batteries to the energy system.

Networks need resources that can reliably be available at times of peak demand and peak network congestion. Demand-side batteries can significantly contribute to solving these problems but their availability has outpaced distribution pricing progress and outpaced meaningful regulatory action.

Only efficient pricing signals can result in New Zealand achieving a low-cost and secure electricity system. These pricing signals will only make a meaningful difference to the tens of billions in infrastructure expenditure if they are introduced urgently – in time for distributors to develop their next pricing adjustment which will need urgent regulatory direction and action.

What's needed:

Mandatory Symmetrical Export Tariffs for distribution pricing

Reducing your own peak usage should be treated economically exactly the same as reducing your neighbour's peak usage (through battery export).This has not been implemented by networks and therefore needs urgent regulatory action, and that action should be to make symmetrical peak export tariffs across all networks mandatory.

[1] By Symmetrical Export Tariffs, we mean the network price charged for peak consumption is also equally paid to customers if they export at peak times.

What are Symmetrical Export Tariffs?

Existing tariffs

Today, most EDBs in New Zealand charge consumers for network services using "time of use" tariffs[2]. These charge consumers a higher price during periods when the network is expected to experience the highest usage – usually mornings and evenings on winter weekdays. During other periods the charge for consumption is lower (sometimes zero). Often these network tariffs are combined with retail tariffs which do something similar: charging customers more for consumption during periods when the wholesale price of electricity is higher – again, typically morning and evenings in winter. The combination of network time-of-use tariffs, and retail time-of-use tariffs, provides a strong financial reward to consumers who reduce consumption at peak times. If the consumer reduces consumption, they reduce their electricity bills.

Where existing tariffs fall short

For a customer with solar and a battery, there is now the very real prospect that not only can they reduce their consumption, but they can make their consumption negative – that is, they can export from their home or business to the network. If this is done during times of high network demand, exporting has the exact same effect on network demand as other nearby consumers reducing their consumption. However, as soon as a household with solar and battery moves from consuming to exporting, the network tariff vanishes. The retail reward remains, but network tariff is absent (see example of Vector's network tariff below, where export is described as 'injection').

Example of one-way asymmetrical tariffs: Vector pricing 2024

Distribution line charge prices for time of use residential and general ICPs from 1 April 2024 *(previous price, if changing)*

Consumer groups and subgroups		Price category type	Price category description	Price category codes	Estimated no. of ICPs (year avg. from 1 April 2024)	Daily $/day -FIXD	Volume off-peak $/kWh -OFPK	Volume winter peak $/kWh -PEAK	Volume injection $/kWh -INJT
Mass Market	Residential - low user	Time of use	Controlled	ARHLC	140,814	0.60 *(0.45)*	0.0369 *(0.0378)*	0.1352 *(0.1313)*	0.0000
				WRHLC	88,474		0.0378 *(0.0387)*	0.1361 *(0.1322)*	
			DER	ARHLD	410		0.0319 *(0.0328)*	0.1302 *(0.1263)*	
				WRHLD	266				
			Uncontrolled	ARHLU	29,487		0.0378 *(0.0387)*	0.1361 *(0.1322)*	
				WRHLU	20,322				
	Residential - standard user	Time of use	Controlled	ARHSC	75,497	1.41 *(1.28)*	0.0000	0.0983 *(0.0935)*	
				WRHSC	57,572	1.43 *(1.30)*			
			DER	ARHSD	240	1.30 *(1.17)*			
				WRHSD	196				
			Uncontrolled	ARHSU	16,488	1.43 *(1.30)*			
				WRHSU	16,647				
	General	Time of use	General	ABSH	23,275	1.74 *(1.52)*			
				WBSH	15,893				

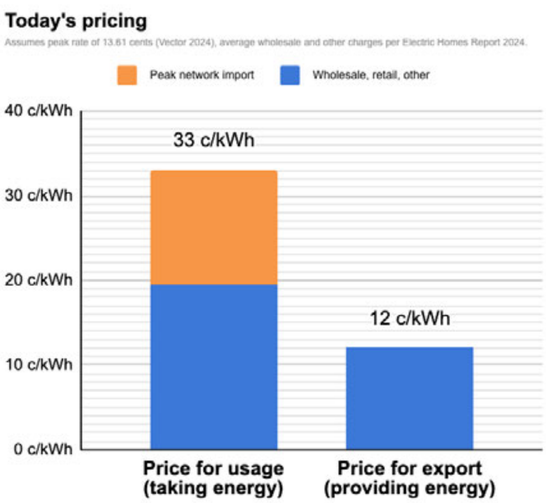
Clearly, the remedy for this situation is for the network price charged for peak consumption to be equally paid to customers if they export at peak times – a two-way tariff or Symmetrical Export Tariff.

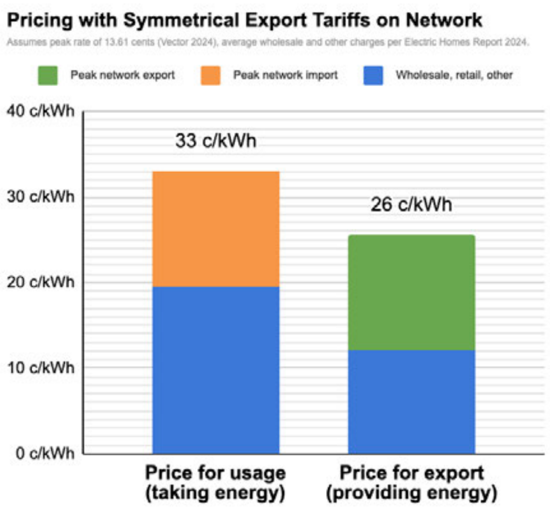
[2] The Electricity Authority's 2023 scorecards showed that "23 out of 29 distributors offer [time-of-use] pricing options for residential consumers and assign consumer connections (installation connection points ICPs) to these tariffs. However, 19 out of 23 lack a quantitative analysis linking network circumstances to the strength of their peak price signals, consistent with cost-reflective pricing." Electricity Authority, "Distribution pricing scorecards 2023: Information paper", para 4.21.

Example of Symmetrical Export Tariffs

The charts below compare today's pricing (on the left) to what pricing would look like with Symmetrical Export Tariffs (on the right). Today a consumer importing (using) electricity at peak is charged both the network peak rate and the rest of the costs of electricity (wholesale, retail, transmission, other). If that consumer exports electricity they are only rewarded with an approximation of the wholesale price – only a fraction of what the consumer pays to import the same electricity. The vast majority of networks do not pay for export during peak times, so the payment to the consumer is reflective of the wholesale price only (i.e. the value of generation) and not any of the value of network peak reduction.

The second chart on the right shows what a Symmetrical Export Tariff would look like (i.e. when the network peak rate is also applied symmetrically for export). This cost-reflective payment for exporting would likely double the payment. This highlights the materiality of the ‘value hole’ that is in today’s tariffs.





Symmetrical Export Tariffs will level the playing field for consumer energy resources that can provide a reliable, peak-reducing service. The investment in batteries that results will then be truly efficient, leading to investment in energy storage that will support both the grid as a whole, and the network/community that the storage is located in.

This brings a much needed degree of competition to monopoly network businesses.

How will this improve security and resilience in the electricity system?

Batteries in homes and businesses are individually small, but have the potential to have a significant impact on the security and resilience of the power system. To provide a sense of the potential significance, 120,000 homes (that is, 5% of households in New Zealand) with a medium-sized battery would have the same responsive peak reduction potential as New Zealand’s largest hydro power station (Manapouri). These would not hold as much energy as Manapouri, but they could output the same power as Manapouri for an hour or two when the system really needs it.

In addition to energy security, these distributed battery resources would provide unprecedented resilience to New Zealand communities. Higher capacity poles and wires still face the same or similar risks to resilience, and can be taken offline by falling trees, unusual weather and more. Distributed solar and battery resources build upon resilience in a way that does not have a single failure point.

How will this help keep electricity prices lower?

If peak export pricing fairly reflects value provided to the network by that export – i.e. reflective of the cost of expanding the network – then if a battery can provide this service at lower cost, the battery should 'win' over the network build (that is how level playing field competition is meant to work). As a result, New Zealand homes and businesses can be confident that the lowest cost combination of batteries and new poles and wires will occur.

This is critical right now because the cost of batteries have declined to a point where they are competitive with supply-side infrastructure. Without pricing that properly reflects their value, New Zealand runs the risk of a future with unnecessarily higher electricity prices, resulting from inefficiently built infrastructure that could have been avoided using lower cost batteries.

Every day that passes without action results in lost opportunities to achieve a more secure and affordable electricity system. As significant investment in networks will occur over the next five years, we can no longer rely on light-handed regulatory guidance and consultation to deliver the outcomes required for the consumer. The Electricity Authority's programme for distribution tariff reform has been solely focused on improving the incentives for consumption, and silent on the need for payments for peak export[3].

This is why it is vital that Symmetrical Export Tariffs are mandatory for all EDBs and are implemented on an urgent timeline before the next tariff period. Six years have passed since the Electricity Authority guided EDBs to provide more cost reflective pricing, with glacial progress as a result. The rapid development of the electricity system for electrification does not have time to wait for this slow pace of progress again, and needs rapid regulatory action – not guidance – to ensure outcomes that build a low cost and secure energy system for the New Zealand people.

In the EA's own words, in 2018[4]:
"Distributors will want to manage the transition to more efficient distribution prices, working with retailers and other stakeholders. Distributors should not wait to start this transition. Consumers experience the adverse effects of inefficient prices now. Also, the size of the problem will only grow over time and become harder to address."

Six years on, it is clear that faster and more effective regulatory action is needed.

[3] In fact, the Authority's May 2024 "Distributed Pricing Reform: Next Steps" paper does not even mention the prospect for batteries to enable export, which seems a significant oversight given that this technology is now widely available and likely to be a primary mechanism to reduce network expenditure.
[4] "More efficient distribution prices: What do they look like?", Electricity Authority consultation paper, 11th December 2018, page i.

The price of solar and batteries are already competing against grid prices and expected to continue to drop in price while grid prices are expected to continue to rise. The chart below[5] has the grid price forecast based on historic grid inflation, with DPP4 it is already predicted that pricing in the next 5 years will significantly exceed this.

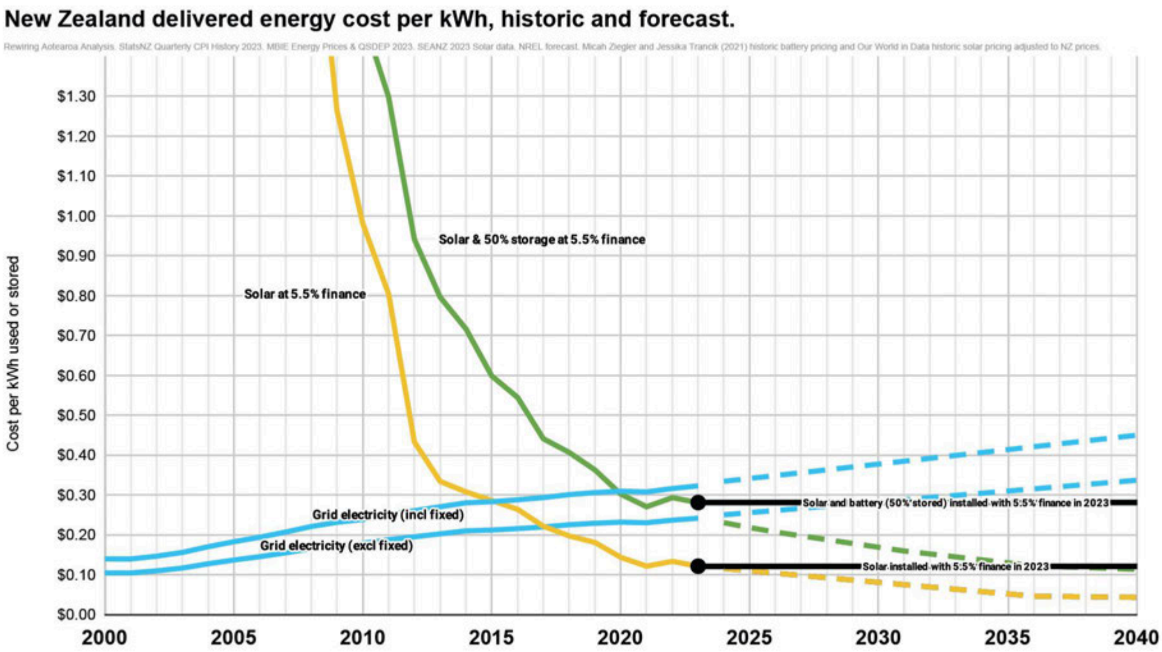


Figure 8 - Solar and battery (50% stored) cost per kWh compared to electricity grid costs both including fixed costs and excluding fixed costs. Today's grid prices based on MBIE and EMI price data, historic and forecast based on electricity Consumer Price Index (CPI). Today's solar prices based on New Zealand solar install pricing at $2000/kW, 30 year lifetime with an inverter replacement. Battery prices based on $1000/kWh available today in New Zealand. Historic solar and battery prices estimated based on international solar module and battery cost curves. Future forecast solar and battery pricing based on NREL Advanced forecast adjusted to New Zealand prices.

As shown by the black lines in the chart, solar and battery purchases effectively buy many years worth of energy upfront. Financing these purchases enables a comparatively flat and stable price per unit of energy into the future. In other words, solar and battery prices don't only compete against today's grid prices, they really compete against the next decade or more of electricity pricing, which has historically risen at a higher rate than inflation[6] and is expected to continue to do so. Demand-side generation and storage (solar and batteries) can reduce peak consumption and simultaneously increase network utilisation to help lower the per unit cost of electricity.

For example, residential electricity networks typically operate at less than 50% utilisation, meaning for most of the day they have 'room' for significantly more electricity to flow along the same wires, and just at peak times they are closer to full utilisation. Demand-side batteries, which are now competitive with grid prices, offer the ability to lower usage at peak and increase usage off-peak, the former enables less infrastructure to be built, and the latter enables a lower per unit price of electricity.

New Zealand's homes, farms[7], and businesses can now provide an unprecedented level of contribution to the energy system, helping to lower the prices of energy for all New Zealanders, and helping to provide a more secure and resilient electricity system overall.

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[5] Electric Homes Report - March 2024 - Rewiring Aotearoa

[6] https://www.stats.govt.nz/information-releases/consumers-price-index-march-2024-quarter/ (see electricity price index)

[7] Electric Farms Report - May 2024 - Rewiring Aotearoa

Do they fit within existing distribution pricing frameworks?

Symmetrical Export Tariffs are aligned with the distribution pricing principles used by the Electricity Authority to provide regulatory direction for EDB tariff reform[8]. These principles are:

1. *Prices are to* ***signal the economic costs of service provision****, including by:*
   a. *being subsidy free (that is, equal to or greater than avoidable costs, and less than or equal to standalone costs);*
   b. ***reflecting the impacts of network use on economic costs[9];***
   c. *reflecting differences in network service provided to, or by, consumers; and*
   d. ***encouraging efficient network alternatives.***
2. *Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.*
3. *Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:*
   a. *reflect the economic value of services; and*
   b. *enable price/quality trade-offs.*
4. *Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.*

There is no question that rewarding homes and businesses for export during times of peak network demand are reflecting the impact of network use on economic costs, in the same way that reducing consumption does. There is nothing magically different between an additional kilowatt reduced, and an additional kilowatt exported from a consumer's premise.

Rewarding export also provides efficient incentives for batteries as a network alternative. If batteries are incentivised to reliably export during peak times, they will defer the need for network investment.

[8] See https://www.ea.govt.nz/industry/distribution/distribution-pricing/
[9] The EA's current direction to EDBs is that peak tariffs should be based on the long-run marginal cost (LRMC) of network investment, as changes in peak consumption today will have a marginal effect on the EDBs future cost of investment (increase or decrease). Batstone (2018) (available on Transpower's website) provides a comprehensive summary of the methods for calculating LRMC for networks, but all centre on a principle that reinforces the need for tariffs to apply to both export and consumption, noting that "ideally the LRMC price should only influence participant decisions when their level of **desired injection or offtake** is expected to change future transmission investment costs. Outside these periods, by definition, the only transmission costs being affected by participants are short-run costs." (page 15, emphasis added)

Requiring retailers to better reward consumers for supplying power

Our goal is to provide incentives to increase uptake of Distributed Energy Resources (DER) (primarily solar) to support energy adequacy.

One of the main options we are interested in examining further is **mandating minimum feed-in tariffs offered by retailers to consumers** to ensure that retailers pass on the full benefits of distributed solar generation.

Within this, there are multiple ways that we could support improved incentives for distributed generation, particularly solar:

- Require retailers to offer feed-in (export) tariffs linked to wholesale prices
- Require retailers to offer time of use-linked symmetrical import-export tariffs
- Require retailers to offer to buyback solar at or above a minimum price (eg, 12c/kWh)

Our initial preference is requiring retailers to offer feed-in (export) tariffs linked to wholesale price.

Policy considerations for implementation	
What would it look like in practice? *Implementation across each of the three options*	**Wholesale-linked tariff** Retailers required to offer feed-in tariffs linked to wholesale price, so household consumers receive true value of energy they provide to system (possibly less certain costs). This would require distributed generation (possibly specifically solar) to participate and could also require a battery if we want to also incentivise solutions for peak capacity issues. The tariff may only be in effect for peak periods or could also be varied to be higher at peak periods and lower outside of peak periods. To mitigate some unintended consequences, the Authority could also require retailers to include wholesale-linked import tariffs. This would add additional complications due to volatility and may reduce uptake if consumers are less willing to engage on shifting load in response to wholesale prices for import. Flick currently offers this plan; wholesale price exports for solar generation. However, they do not currently offer a wholesale price import plan because of high volatility.
	Symmetrical import-export tariff This option would require retailers to offer a plan that included symmetrical rates for importing and exporting energy, within a certain spread (to enable the retailer to recoup costs). Retailers would be able to vary the rates to provide peak/off-peak/night rates. This would not necessarily require consumers to

Policy considerations for implementation	
	have battery storage as time-of-use tariffs would incentivise exporting energy at peak times. Octopus offers this plan currently in the UK, with a peak, off-peak, and night rate and an 8p/kWh difference between import and export (with significantly higher prices than in New Zealand). Mandating this has also been proposed by Rewiring Aotearoa.
	Minimum export tariff Alternatively, the Authority could set a minimum solar buy-back rate to be offered by retailers. This could vary by time of export or be an overall rate. Indicatively, most retailers offer solar buyback rates of between 8-13c/kWh. Some smaller retailers do not offer solar buyback. If the Authority were to set a mandatory minimum solar buyback rate, it could indicatively be set at 10c/kWh off-peak and 15c/kWh peak, or 12c/kWh anytime.
Relevance	Only 3% of New Zealand households have solar panels (compared to 40% in Australia). This proposal could assist with energy shortage by stimulating household investment in rooftop solar. Including battery requirements would also address peak capacity issues.
Efficacy	Increased investment in household solar panels and batteries could increase energy production, as well as potentially reducing the need for transmission and distribution network upgrades in some places. As solar and battery penetration increases, this could stimulate additional investment in services by aggregators and flexibility service providers. Including incentives for batteries (through time of use changes to tariffs) will help mitigate the 'duck curve' effects of increasing solar penetration. However, increased investment in rooftop solar may offset potential investments in grid-scale solar and other renewables, which tend to be cheaper to install (if not cheaper for consumers).
Consumer benefits	Consumers with rooftop solar and batteries benefit through receiving wholesale-price-linked retail feed-in tariffs. Non-generating consumers pay relatively more, however, paying a wholesale-price-linked feed-in tariff for new injection is revenue-neutral for a retailer (new injection requires no additional funding). Any increase in feed-in tariffs will reduce the payback period for investing in solar and eventually reduce household energy bills.

Policy considerations for implementation	
	Consumers without solar panels will not immediately benefit from this proposal. However, there is the potential for all consumers to benefit in the long term due to improved energy supply, security of supply, resilience and lower electricity prices. There are also distribution and equity issues with the proposal. Requiring specific benefits above market rates for people with solar (and battery) would disadvantage those without. Typically, households that can afford solar upfront are wealthier and subsidising their electricity (indirectly) is unnecessary. This is a challenge we will have to work through in implementation to ensure we are regulating on behalf of *all* consumers.
Timing	This could be implemented as a medium-term option. Code changes could be implemented this year, with pricing changes possibly from mid-2025. Impact would be relatively fast—rooftop solar does not have a long lead time and if the incentives were sufficiently strong it could significantly increase the rate of uptake (currently around 10,000 ICPs per annum). Possible issues with installation bottlenecks if demand was sufficiently high. This would potentially interact with a parallel option to introduce symmetrical import-export distribution tariffs paid/received by retailers. The Market Development Advisory Group supported several options to improve the uptake and visibility (but not mandating) of demand-side flexibility-rewarding (DSF) tariffs. DSF-rewarding tariffs support capacity adequacy as they shift the time at which consumers use electricity. Specific distributed generation-rewarding tariffs would also support energy adequacy.
Costs	**Authority costs:** Code amendment proposal would require some external resource.
Risks *Risks across each of the three options*	• **Export congestion at peak solar/low demand periods** Could cause export congestion during the day, requiring more network investment to fix (this has already occurred in Australia, due to feed-in tariffs). Linking to the wholesale price would mitigate this concern, but it is unclear whether price signals would sufficiently impact consumer behaviour. • **Possibly unnecessary** Some retailers already offer similar plans; Authority intervention in retail market may be unnecessary and does not support market outcomes. If there was demand for these types of plans, there are already options available (for

Policy considerations for implementation	
	example, higher solar buyback rates, often with time of use specific tariffs, and a wholesale-linked buyback rate). • **Regressive distributional effects** High to middle income households who can afford the upfront costs of solar panels benefit most. Retailers may pass increased costs on to those without solar (or more specifically, if retailers face tighter margins on customers with solar, they may seek to increase margins elsewhere). • **Difficult to remove** Once introduced, a mandated feed-in tariffs could be difficult to amend, as consumers with rooftop solar would have a financial interest in the scheme. • [Wholesale-linked tariff-specific] **Cycling issues** Creates an incentive for consumers on a fixed import tariff (likely less than 30c/kWh) to cycle their batteries to take advantage of higher export rates at times of higher wholesale prices, which does not contribute to energy or capacity solutions. Our understanding is that Flick already experience these cycling issues at a low level on the plan they offer. • [Symmetrical import-export tariff-specific] **Herding issues** Mandating specific time of export rates for solar buyback may create herding issues where consumers with insufficiently granular price signals start exporting at the same time. • **Some retailers do not offer solar buyback rates** A small number of retailers do not offer solar buyback rates (for whatever reason), and mandating minimum solar buyback rates in some form may cause either other retailers to stop offering solar buyback rates, or would force those retailers who may not be equipped to offer solar buyback to do so.

Part 12B
Distributor quality and information requirements and pricing methodologies

[Drafting note: Have currently drafted this as a separate Part, but it may be better for these provisions to sit in Part 12A. Another alternative is to amend the DDA and redraft so all these requirements are contractual requirements in the DDA]

12B.1 Contents of this Part

This Part specifies:

(a) quality and information requirements for **distributors**, in relation to access to **distribution networks**; and

(b) **pricing methodologies** for **distributors**.

[Drafting note: Query whether it is useful to include this clause, the intention is to clearly set out that the following requirements are made in accordance with our power to regulate the above in the Code, noting that there are other parts of the Code that already regulate using this power but with no reference to it (such as the DDA)]

12B.2 Definitions

(1) In this Part, unless the context otherwise requires,—

add any necessary definitions here

(2) Any term that is defined in clause 1.1(1) of this Code or the **Act** and used, but not defined in this Part, has the same meaning as in clause 1.1(1) of the Code or the **Act**.

[Drafting note: Alternatively the definitions could be placed into clause 1.1(1), but keeping them here is easier to read]

Reduction in charges for injection

12B.3 Certain distributors must reduce charges in respect of injection for residential customers

(1) A **distributor** that adopts a pricing methodology that provides a residential customer pricing plan that has line charges at a higher variable rate (c/kWh) for **electricity** consumption during peak periods (compared to off-peak periods) must provide under the same plan a reduction in charges (negative tariff component) for **electricity injected** into the **distributor's network** during those peak periods calculated in accordance with subclause (2).

(2) The reduction (negative tariff component) must be no less than the amount determined in accordance with the following formula:

[REAF] × (PD) x (PI)

Where:

REAF is the residential export adjustment factor

PD is the c/kWh "peak differential" and calculated as PR – OR where

PR	is the c/kWh rate for the line charge under the plan for peak periods
OR	is the c/kWh rate for the line charge under the plan for off-peak periods
PI	is the volume of electricity (kWh) injected during peak periods.

(4) The residential export adjustment factor for residential customers must be set at between 0.5 and 1

(5) A **distributor** may limit the reduction of charges under this clause such that the total line charges in respect of any given ICP do not fall below zero.

(3) A **distributor** cannot adopt a pricing methodology with a peak differential lower than the peak differential in that distributor's pricing methodology that applied at 1 April 2024.

12B.4 Certain distributors must reduce charges in respect of injection for non-residential customers

(1) A **distributor** that adopts a pricing methodology that provides a non-residential customer pricing plan that that has line charges at a higher variable rate (c/kWh) for **electricity** consumption during peak periods (compared to off-peak periods) must also comply with Subclauses (2), (3), and (4) of 12B.3.

(2) A **distributor** that adopts a pricing methodology that provides a non-residential customer pricing plan that charges based on maximum demand during peak periods, must provide under the same plan a reduction in charges (negative tariff component) for **electricity injected** into the **distributor's network** during those peak periods calculated in accordance with subclause (3).

(3) The reduction in charges (negative tariff component) must be no less than the amount determined in accordance with the following formula:

[NREAF] × (PI)

Where:

NREAF	is the non-residential export adjustment factor
PI	is the volume of electricity (kWh) injected during peak periods.

(4) The non-residential export adjustment factor for non-residential customers must be set at between 0.5 and 1

(5) A **distributor** may limit the reduction of charges under this clause such that the total line charges in respect of any given ICP do not fall below zero.

12B.5 Definition of peak periods

(1) Peak periods under 12B.3 (1) and 12B.4 (1) must be pre-determined in the **distributor's** pricing methodology.

(2) Peak periods under 12B.4 (2) may be pre-determined in the **distributor's** pricing methodology or may be signaled through some other means.

(3) Pre-determined peak periods may be times of day, or months of the year, or both

(4) Peak periods must be determined based on the **distributors'** estimate of the time periods in which its network is likely to experience network constraints in future.

12B.6 Exemptions

(1) A **distributor** that has adopted as at 1 April 2024 a pricing methodology that provides a customer pricing plan that charges day/night tariffs is exempt from Parts 12B.3 and 12B.4 in respect of those customers on a day/night tariff

(2) A **distributor** is exempt from subclause (3) of 12B.3 if:

(a) forecast congestion is materially lower than it was in 2024

(b) a material error is found in the prior calculations setting PD.

(3) A **distributor** that discloses export congestion under Part 6.3 clause (2) is exempt from 12B.3 and 12B.4 for the sections of network and periods of time disclosed.

12B.7 Dispute resolution

(1) Subject to subclause (2), Schedule 6.3 of this Code applies to any dispute between a **participant** and a **distributor** about the application of the requirement in clause 12B.3, with all necessary modifications, and with the reference to the distributed generation pricing principles set out in Schedule 6.4 to be read as a reference to the requirement in clause 12B.3.

(2) **Participants** and **distributors** may agree to resolve disputes by a different method, in which case that method applies.

(3) This clause does not affect any person's right to make a complaint to a dispute resolution scheme under section 95 of the **Act**.

[Drafting note: Have simply mirrored the dispute resolution process for load and distributed generation in Part 6. An alternative would be to deem the reduction requirement to be default terms and conditions in all distribution agreements as per section 44A(2) of the Act, and apply the dispute resolution processes in those agreements (ie. the DDA) – this could potentially significantly reduce the compliance burden on the Authority, but a question might arise about the appropriateness of this and why Part 6 is treated differently]

12B.8 Transitional arrangements

(1) [Transitional safeguards to be developed as necessary]

Requiring distributors to offer symmetrical tariffs

(Rewiring Aotearoa's 'Symmetrical Export Tariffs' proposal)

1.1. A proposal for 'symmetrical export tariffs' has been put forward by Rewiring Aotearoa (see separate PDF document). The proposal is summarised at Box 1.

1.2. Under this proposal the distributor would provide a rebate on distribution charges when a household exports electricity (that is, injects electricity into the network) at times of peak demand. This could be achieved by setting a Code requirement (or pricing principle) for distributors regarding pricing for injection during peak periods. The Code requirement could require a tariff component with a negative rate for injection, identical to the tariff rate for peak consumption (as Rewiring Aotearoa has proposed) or set at some proportion of the consumption peak rate (eg, 50%).

1.3. The proposal is designed to be applied to small-scale generation (eg, residential battery storage). It provides a financial incentive that could encourage households to invest in battery storage, alongside rooftop solar. This could help to address the energy shortage, improve security of supply and ultimately lower electricity prices.

Discussion

1.4. Rewiring Aotearoa's proposal for symmetrical export tariffs is designed to encourage investment in household solar and battery storage. As noted by Rewiring Aotearoa, household batteries have the potential to have a significant impact on the security and resilience of the power system,[1] and can keep electricity prices lower, by reducing network infrastructure requirements and shifting usage off-peak.

1.5. Rewiring Aotearoa's proposal has some key strengths:

(a) It could encourage investment and operation of household batteries in places where more injection is required to address a distribution constraint (if there is enough data available for constraints to be incorporated in pricing) – particularly if the injection is required to be controllable. This could reduce required network infrastructure costs. In principle, it could be targeted to areas where peak charges are warranted due to high load on the network.

(b) It could help produce more energy by increasing investment in rooftop solar (assuming household batteries are often purchased as a package with solar).

(c) The proposal is simple and would be relatively low cost for distributors to implement in their pricing. Most distributors already have tariff codes for injection,[2] and these could be split into peak and off-peak rates.

(d) It relies less on distributors' discretion (compared to a voluntary option), so it could be effective even if distributors' commercial incentives were not aligned with efficiency.

[1] Rewiring notes that 120,000 homes (5% of households in New Zealand) with a medium-sized battery would have about the same responsive peak reduction potential as our largest hydro power station (Manapouri).

[2] Commonly these are set at 0c/kWh to assist in data collection.

Box 1: Rewiring Aotearoa: mandatory symmetrical export tariffs

Rewiring Aotearoa considers the electricity market 'was designed for a one-way flow of electricity and does not fairly or cost-reflectively reward services to the system provided by households and businesses – which are now becoming infrastructure'.[1] It recommends implementing two-way tariffs quickly to reduce unnecessary infrastructure costs. It considers:

> … if a consumer exports electricity, they are only rewarded with an approximation of the wholesale price … the vast majority of networks do not pay for export during peak times, so the payment to the consumer is reflective of the wholesale price only (ie, the value of generation) and not any of the value of network peak reduction.[2]

Rewiring Aotearoa submitted that the Authority should:

> ... not only require TOU consumption tariffs, but also peak-targeted export tariffs for batteries. As far as we are aware, EDBs do not reward peak-aligned export, even though the impact of the marginal kW is identical between the last unit of import reduction, and the first kW of export.[3]

This means that for the network price charged for peak consumption to be equally paid to customer if they export at peak times.[4] Rewiring Aotearoa explains this as:

> … reducing your neighbours peak load should be treated economically the same as reducing your own peak load. Today, reducing your neighbours peak load is treated as zero value to the network - even though this is demonstrably false. Yet if the neighbour reduces their peak on their own, the value will be provided to them. This is especially apparent with business/farm batteries - which can reduce peak loads of 20 homes or more, and today have no incentive to do so and can sit idle.[5]

The logic of this idea is that an additional incentive is needed to encourage investment in household battery storage, which can lead to cost-effective reductions in the cost of new network assets that would otherwise be needed to meet peak demand growth. Significant peak demand growth is likely in coming years, so the absence of appropriate incentives may be a material problem.

Rewiring Aotearoa also said:

> …If peak export pricing fairly reflects value provided to the network by that export – ie reflective of the cost of expanding the network – then if a battery can provide this service at lower cost, the battery should 'win' over the network build (that is how level playing field competition is meant to work). As a result, New Zealand homes and businesses can be confident that the lowest cost combination of batteries and new poles and wires will occur.[6]

[1] Rewiring Aotearoa. 2024. Electric Homes. The energy, economic, and emissions opportunity of electrifying New Zealand's homes and cars. P 4 https://www.rewiring.nz/electric-homes-report

[2] Rewiring Aotearoa. 2024. Symmetrical Export Tariffs - Unlocking a more secure and affordable electricity system. P 2.

[3] Rewiring Aotearoa. 2023. Submission on: Targeted reform of distribution pricing. P 8

[4] op. cit., Symmetrical Export Tariffs - Unlocking a more secure and affordable electricity system. P 2.

[5] Correspondence, Rewiring Aotearoa'

[6] Ibid, P 4.

1.6. The symmetrical export tariffs proposal is particularly likely to be efficient where the accurate cost-reflective rate is known with sufficient granularity and/or where it is possible to be confident that there is low risk of unintended consequences.

1.7. On the other hand, this option may be less efficient if there is a high risk of unintended consequences (such as injection causing network constraints). Below are some factors to consider indicating potential disadvantages of this proposal:

(a) A distributor can rely on injection to reduce required network investment if the injection is reliable and consistent. Consistency of injection may be achieved in locations where there are a large number of independent parties injecting. For example, at a location with many solar and battery installations, if some happen not to inject at a given time, many others are still likely to do so. However, in situations where there are only a few sources of injection in a local area of the network, injection may be less consistent and reliable.

(b) Distributors may have limited visibility of the low-voltage network, including where increased injection might lead to network constraints. Network peak charges today are set at network-wide levels for simplicity reasons. However, available network capacity often differs within a distribution network, meaning the network-wide peak signal may be too strong or too weak compared to local network circumstances. Symmetrical export tariffs could exacerbate localised congestion in some circumstances, potentially resulting in inefficient investment in sections of the network.
Box 2 notes the experience with excess injection in South Australia.[3] Box 3 notes the regulatory response in Australia: a rule change in 2021 to allow tariffs for injection: both positive and negative.

(c) Pricing for injection can create local network constraints if it results in 'herding' behaviour, where multiple distributed energy resources are switched on or off at the same time in response to price signals that do not reflect local network constraints.
Such signals could include wholesale market prices and could potentially include distribution prices, if those prices are not granular enough to reflect local network constraints. The herding problem is discussed at Box 4, with reference to the network structure diagram set out at Box 5 below.

(d) Distributors' incentives might be pushed towards over-constraining injection if pricing is mandated. This is because the risks of over-constraining injection compared to under-constraining are not symmetrical.[3] Over-constraining may merely result in marginally less injection than is efficient, while under-constraining could result in damage to network infrastructure.

(e) Efficient payment for non-network solutions would imply that distributors pay the minimum amount required to encourage injection to avoid additional investment. Mandating a payment level might lead to distributors overpaying for non-network solutions compared to the status quo.

[3] Over-constraining: a scenario where the EDB constrains injection by DG even though there is network capacity available. Under-constraining: a scenario where even though there is no spare network capacity available, the EDB fails to constrain injection by DG.

Box 2: Potential impact of rooftop solar installation: South Australia

In Australia, due to the rapid increase in household solar installations, there has been a surplus of electricity generated in the middle of the day over the last couple of years. This excess energy is fed into the grid, leading to instances where supply exceeds demand, causing network congestion and reliability issues. This is commonly referred to as the 'solar trough' or the back of the 'duck curve'.

Figure 1 below shows average daily operation demand in South Australia, illustrating the middle-day slump in demand. While this is significant, the duck curve is even more pronounced in SA Power Networks' (SAPN) residential network.[1]

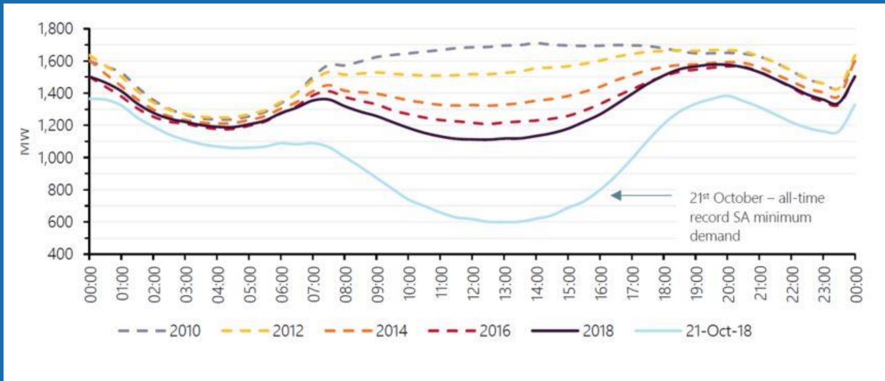


Figure 1. AEMO 2019 Quarterly Energy Dynamics – Q4 average daily operation demand in SA

Figure 2 below shows SAPN's average residential load profile for 2016-17 and predicted load for 2025-25, based on Australian Energy Market Commission (AEMC) forecasts for PV and batteries. This graphic shows that even without the impact of increased solar and storage, demand is well into negative in the middle of the day.

This issue is more pronounced in some Australian networks, such as in South Australia. This issue led SAPN in July 2020 to seek an amendment to the regulations to address this issue—resulting in the AEMC updating the National Electricity Rules in 2022.[2]

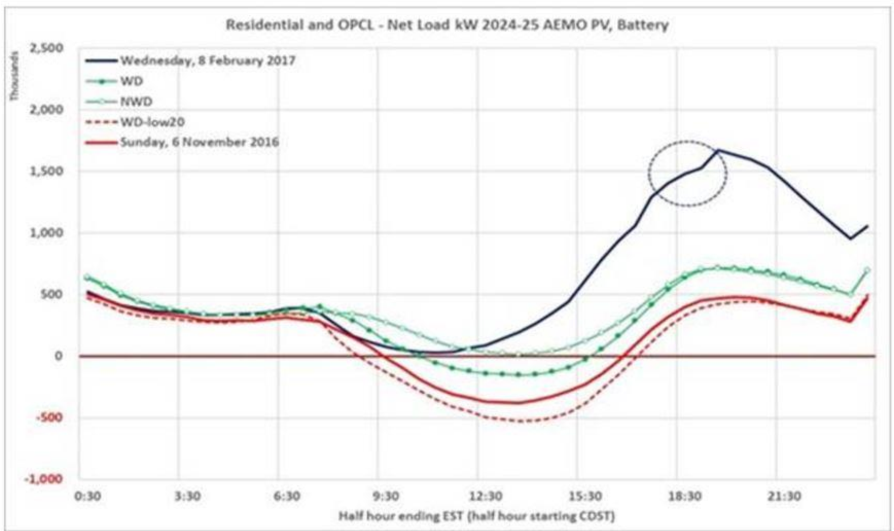


Figure 2. Illustrates an average maximum demand day, work day, non-work-day and minimum day Residential network demand is lower on work days as more homes are vacant during the 'solar sponge' period.

1 https://www.energynetworks.com.au/news/energy-insider/midday-the-new-off-peak-time-for-electricity/

2 https://www.aemc.gov.au/sites/default/files/documents/consultation_paper_-_der_integration_-_updating_regulatory_arrangements.pdf

Box 3: Export (injection) tariffs: 2021 rules change in Australia

In August 2021, the Australian Energy Market Commission (AEMC) updated the regulatory framework to integrate DER such as small-scale solar and batteries more efficiently into the electricity grid.[1]

The new rules contain obligations on distributors to support more DER connections to the network. As part of its decision, the AEMC removed the prohibition on distribution businesses from developing export pricing options and allowed networks to propose the introduction of export tariffs to the Australian Energy Regulator (AER).

In May 2022, the AER published the Export Tariff Guidelines.[2] An export tariff, according to the AER, is one that includes a charging component for exporting energy into the grid). It can include:

- a **positive charging** component, or a cost for exporting customers, to indicate when exported energy would drive future network investment.
- a **negative charging** component, or rebate for exporting customers, when the network would benefit from exports, and customers can be rewarded for exporting
- AER provides the following example of two-way-pricing that incorporates both positive and negative charges to exporting (injecting) consumers:

Residential two-way tariff	Time period	Charge per unit	Price per unit (cents)
Fixed charge	Daily	c/day	50.0
Peak consumption charge	4 pm – 9 pm	c/kWh	20.0
Shoulder consumption charge	9 pm – 10 am	c/kWh	5.0
Off-peak consumption charge (solar sponge)	10 am – 4 pm	c/kWh	1.5
Export peak rebate	4 pm – 9 pm	c/kWh	20.0
Export charge* applies to exports > 2 kWh/day (that is, the basic export level is 2 kWh/day).	10 am – 4 pm	c/kWh	1.5

The current approach of the Australian regulator (through guidelines) is characterised by the following:

- The Guidelines are non-binding and are intended to be principles-based rather than prescriptive to allow for differences between distributors.
- They offer information and instructions to distributors and other stakeholders on how networks should explain future proposals for export tariffs and define the rates.
- The AER will not approve export pricing proposals unless a distributor can, through the regulatory proposal process, demonstrate its need.

When proposing export tariffs, distributors need to consider the individual circumstances of their network, the potential impacts on customers if export tariffs are not introduced, and the current or estimated future DER penetration on the network. An essential aspect of justifying the need for two-way pricing is engaging with stakeholders.

The AER emphasises that export tariffs have several benefits, such as promoting efficient network use and enabling fair cost recovery. Additionally, implementing export charges and providing rewards for exports where appropriate and during specific times can foster the adoption of new technologies, services, and business models, thereby delivering a wide array of benefits to customers, networks, and the environment.

Box 4: The ‘herding’ problem

The ‘herding problem’ refers to the fact that neither the prevailing wholesale price, nor dispatch instructions from the system operator reflect distribution constraints. This problem is exacerbated by the fact that most networks have been built a certain degree of diversity in maximum demand.

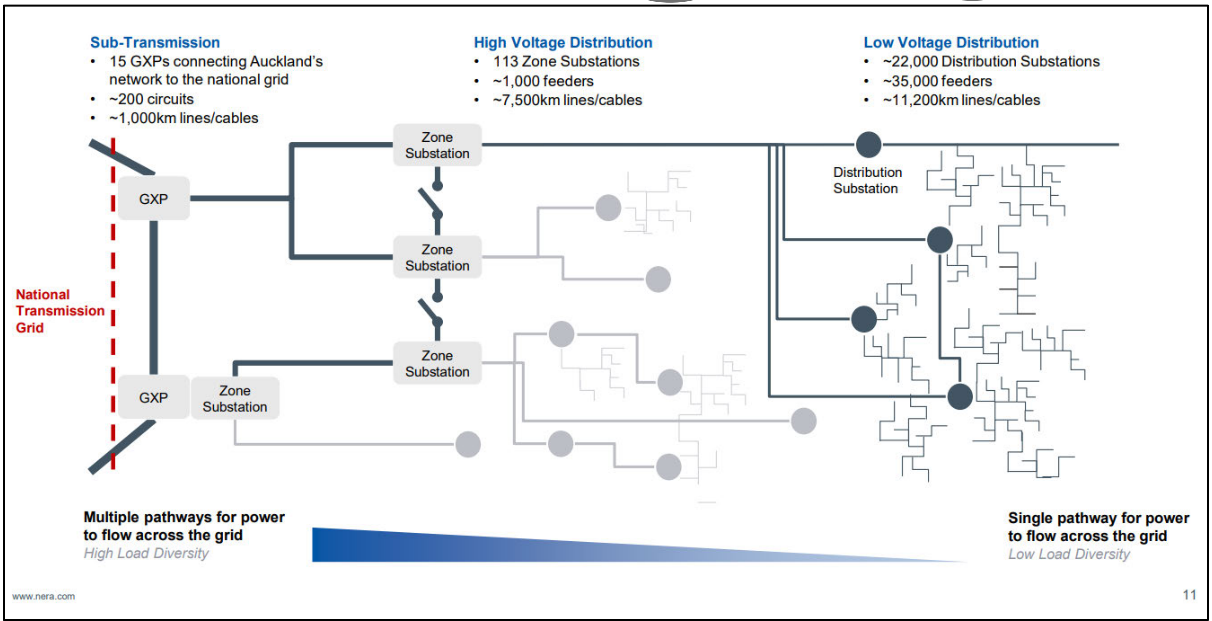
By way of example, low-voltage networks have been sized on (and designed for) observations of ‘after-diversity maximum demand’ (ADMD), or coincidental demand, which vary but are typically in the order of 2.5-5kW per household, despite the typical residential connection being ~14kW. By way of example, low-voltage networks have been sized on (and designed for) observations of ‘after-diversity maximum demand’ (ADMD), or coincidental demand, which vary but are typically in the order of 2.5-5kW per household, despite the typical residential connection being ~14kW. Vector, in a letter to the Authority has raised this problem as below:

‘It is not hard to imagine that, even in summer, few (if any) networks would be able to safely accommodate a material proportion of households’ 7.4kW EV chargers and 3-4kW hot water cylinders all attempting to be dispatched ‘on’ in the middle of the night, in response to a rapid fall in national spot prices (perhaps driven by a rapid increase in wind generation). This is an entirely reasonable scenario for the future market as designed, but again we suspect awareness of this across the sector is low’ – Vector submission to MDAG

This problem is compounded because many distributors will have sections of network with relatively few ICPs. If the transformer is sized for those few ICPs, it is much more likely that those ICPs unintentionally coordinate (in response to a price signal for example) and overload the transformer.

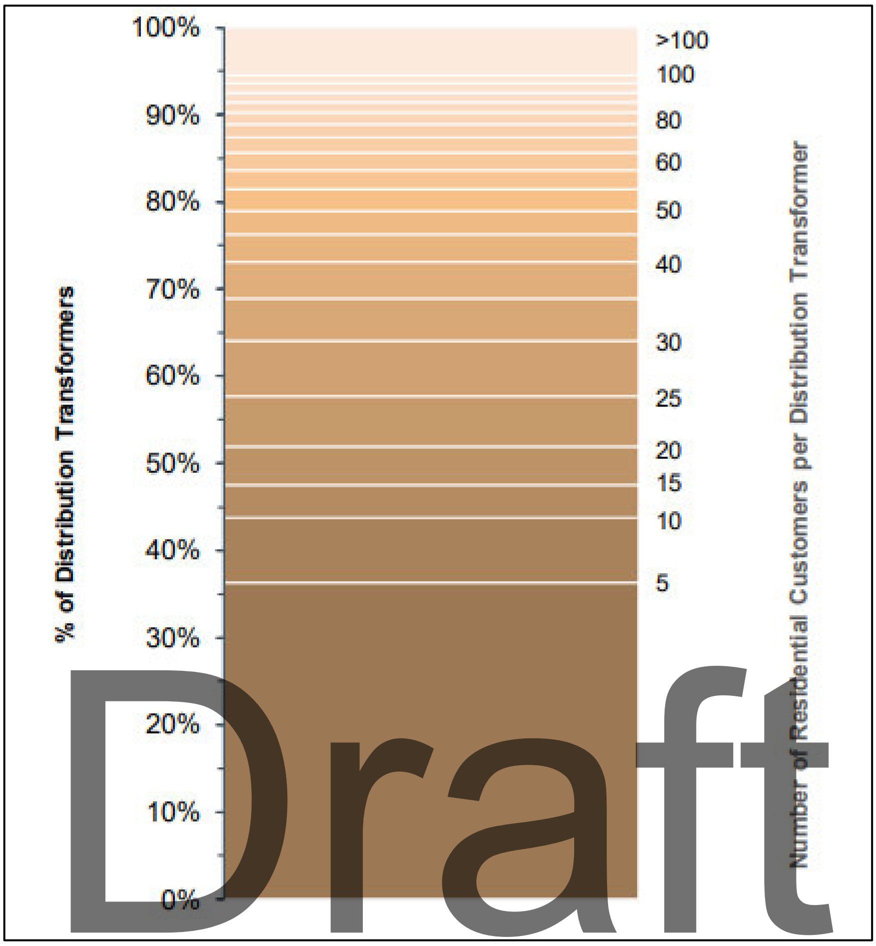
The diagram at Box 6 below (source: Vector) shows that 35% of distribution transformers in Auckland have five or fewer residential ICPs.

Box 5: Distribution network structure[4]



[4] Source: https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

Box 6: 80% of Auckland distribution transformers have fewer than 50 residential ICPs[5]



[5] Source: https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

EAAG Sub Group Letter On Measures To Improve Price Signals For Distributed Energy Resources

4 December 2024

XXXXXX

I am pleased to deliver the report on the work of the Cost Reflective Tariffs Subgroup of the Electricity Authority Advisory Group (EAAG). This first report under the Authority's new Advisory Group structure is an important milestone as we evolve how the Authority and Advisory Group iterate to develop well-informed regulation, quickly and robustly.

In delivering this, we have worked closely with the Authority team in their pre-consultation framing to balance the opportunities to 1) work with agility, efficiency and a tight scope and 2) independently provide an appropriate level of expert advice to the staff and the Authority within this scope.

With this approach pioneering practice that is different to recent Advisory Groups, in addition to our observations and recommendations, we have included additional comments. These cover the context and scope and the limitations to our work and advice for this 6-week, two-workshop sprint of work.

We report by exception on material matters where the consultation papers may

- not sufficiently reflect matters we have identified and/or
- not provide opportunity for comment and/or
- present a preferred proposal where the majority of the advisory group have material concerns that are expected to resonate with a significant proportion of stakeholders

We also provide comment on substantive matters that arose in our discussions but are out of the current scope of work.

Contents

1. Key Messages

1.1. What we are reporting on

We are reporting on 3 measures to improve price signals for distributed energy resources. These include:

- "Mandating cost-reflective distribution injection tariffs" – considers and addresses issues with DG pricing signals for mass market customers specifically. This paper covers the Task Force recommendation 2A.
- "Mandating time-varying retail price plans for consumption and injection" –considers and addresses the issue of the existing market not delivering sufficient retail options for consumers to benefit from shifting their consumption or injection. This paper covers the Task Force recommendations 2B and 2C.

This report covers the material matters identified in our engagement with Authority staff during their preparation for draft consultation proposals having regard to how these matters are captured in those proposals.

1.2. Agile approach balances rewards and risks

- It has been an important opportunity working with the EA team on this high cadence project to address important consumer issues at pace and robustly. We recognise the benefits that consumer and industry stakeholders bring to early analysis and how this can assist in understanding risk-reward trade-offs to 1) action measures to progress at pace and/ or 2) qualify projects where more (or other) work is needed. We detail below the limited scope applied in this work.

- We acknowledge the pace at which the Authority has sought to progress selected new measures in response to market conditions and real consumer needs for the energy transition. The scope for this work engaged the Advisory Group only after a set of proposals had been identified. This missed the opportunity for the Group to engage with identifying the underlying problem and root cause analysis and so contribute to the full range of options the Authority has or the timing/ sequencing of those options – alongside other Authority programmes - for the most robust, timely regulation. This phasing of our work underpins a number of our key observations below and we look forward to opportunities for the EAAG to contribute at this earlier, more formative stage on future EA work. *We note again the specific context of this work and that the new EEAG is working with the Authority management to optimise the timing and levels of EAAG engagement with work programme items and the strategic framing of this work. The Subgroup will prepare a separate management letter on the process to contribute to how we function to support the Authority to develop well-informed regulation, quickly and robustly.*

1.3. Key in scope observations

- **The material matters that our engagement identified are sufficiently addressed in the consultation papers to provide an opportunity for stakeholders to share views.** We thank the team for their level of engagement, are pleased to advise that the material matters we discussed are reflected in the consultation and note the process as an effective dialogue to further develop existing proposal with agility.

- **Readers of the consultation papers will benefit from further context on how these measures fit in the overall Authority strategy.** Several of our comments illustrate how we believe our work would have been more efficient, targeted or have better impact or the importance of the interdependencies of these measures with other Authority work (or possible interventions by other agencies) to the timing or scope of these proposals. Whilst recognising that interdependent measures are identified in selected places throughout the proposals, we recommend a specific section at the start of each document sets out the strategic fit with related items in the Authority work programme, expected timing of implementation and impact from these measures and how these proposals fit.

- **There were material concerns expressed by some members on the pricing efficiency and equity impact of network injection rebates (2a)** with few injecting resources currently available, some sources of injection (e.g. solar PV) having a very low expected coincidence with availability when constraints are most material, risk that less value can be offered to other solutions (e.g. aggregators) reducing their growth and equity concerns regarding the distribution of these resources. The group agree that we need to ensure the right incentives are in place for consumer resources to participate, scale and enable solutions for equitable access to the benefits of these. However the majority view was that this broad based signal is not the right approach for the above reasons, or this measure should not be taken in isolation of, or prior to, other measures. *We note the consultation papers provide appropriate opportunity for comment.*

- **There were significant concerns expressed by some members that battery injection that is not managed by the network cannot be relied on to defer network investments (2a)**. Network deferral decisions require certainty that the alternative capacity will be delivered when it is needed, for a term sufficient to support deferral of investment. Intermittent injection that is rewarded simply through the injection rebate may not be available and respond when it is needed (and will have no/ limited visibility to the network). A minority contra view held that network planning considers growth based on after diversity maximum demand and as the habitual use of battery systems will be reflected in that demand profile, planners will by default include it in planning decisions alongside all the other demand variable hidden in the demand profile signal. *We note the consultation papers provide appropriate opportunity for comment.*

- **There were material concerns expressed across the group about the competition implications of mandating time varying retail plans for consumption (2b) and mandated time varying retail plans for injection (2c)**. Concern was expressed across the Subgroup of unintended consequences arising from intervening in the competitive retail market.

    - While not directly in scope, the Subgroup believes that the sequencing of the Package 1 and 2 measures requires serious consideration by the Authority prior to any final decision on Package 2 measures. A lack of competition in other parts of the value chain could be contributing to stifled retail competition which then results in the lack of retail market activity that Package 2 is addressing. Regulation of retail pricing may then result in unintended consequences if the regulatory structure stifles innovation and/or competition in an otherwise open market.

    - There was a minority view expressed in the group that there is clear evidence based on retail market share trends, hedge market activity (both ASX and OTC) and retail market pricing that current market settings are disadvantaging retail businesses from growing their businesses. The minority view is that Package 2 measures should be put on hold until at the very least all Package 1 measures are explored, the root cause of the lack of retail expansion is identified and relevant regulatory remedies are implemented and given time to flow through the market.

    - In addition to the importance of clarity on how these measures fit with work to address the issues targeted in package 1 measures, clarity is important for the fit and timing with improved access for consumers (and their service providers) to digital information and consumer information tools needed to enable consumers to make time of use-based tariff choices.

    - As an example of the potential for unintended consequences, this intervention risks the potential perverse effect of competitively disadvantaging an innovative independent retailer. Presenting consumers with a minimum mandated offer from an incumbent retailer that appears to meet their needs, risks spreading the consumer segment interested in these offers across incumbent retailers before innovative participants have a real or perceived level playing field to compete for these customers[1]. This may shrink the available market for these independents at a

[1] A parallel could be drawn with the effect of many brands of the same product on supermarket shelves. A dominant producer of a laundry powder for instance may choose to offer multiple brands or versions of their product. A benefit of this is that consumer attention and demand will be split across these products and make

time their market growth is constrained. Concern was expressed that 1 April 2026 implementation does not leave much time for related market, open data and consumer comparison tool interventions to be effective and remove real or perceived barriers to a level playing field. Members recommend that the implementation, effective monitoring and follow up on these measures are treated as a matter of urgency.

- Whilst members note that the requirement is for retailers to offer a time varying tariff (and so does not inhibit other innovative offers) and the intervention is expected to be limited to a small number of larger retailers, concern was expressed that the added focus on one tariff evolution could inhibit other innovation. For instance, the UK Octopus Energy 'zero bills' homes innovation for highly flexible energy use homes would not qualify as either a time-of-use tariff (2b), or comply with an obligation to reward injection in a time-varying or cost-reflective way (2c), but nevertheless provides consumers with huge incentives and rewards for flexibility, in a highly engaging way. 2a could be an enabler of such an offer in New Zealand, provided it was not coupled with a requirement for the injection rebate to be passed through to consumers directly. We need to be careful not to shape regulation around more 'traditional' retail constructs, and certainly not create barriers to new ways of engaging consumers.

- We acknowledge that there are very few offers to consumers with time varying retail tariffs for injection (and at least one of these is limited in what consumers can access it) and a minority perspective was that action here warrants particular attention for the benefits of 2a to reach consumers. However, any intervention needs to ensure that it does not limit how retailers package this value, so long as it works to reward consumers who inject at peak.

- Some members acknowledged the case presented by the Authority that a significant shift in consumer engagement requires awareness of and access to offers to consumers that reward their flexibility to be widespread and an established norm. This intervention is one option to drive this new norm. Members noted though, other tools are available to shift consumer awareness and support building capability that do not have the same risks from direct intervention in retail market competition e.g. shifting energy education focus from efficiency (informed by how much energy is used that locks in historic behaviours) to flexibility and consumer outcomes focus (e.g. efficiency informed by cost of energy). This focus opens up multiple pathways for consumer change without mandated tariffs including channels that can deliver high, direct reach to consumers. We note that some of these interventions need partnership with other agencies.

- A view was also expressed that time varying retail plans for investors with solar PV may build consumer expectations of price levels for PV that will not be sustained

it harder for a new entrant to grow their brand (regardless of its real benefits to consumers). Mandating retailers serving the vast majority of consumers to offer time varying prices risks diluting the market opportunity for more innovative and value adding services.

when there is high penetration of solar. It is important to help consumers understand the risks of future price changes when making investments today.

- *We note the consultation papers provide appropriate opportunity for comment.*

- **Ensuring a level playing field between small and large Distributed Generation.** There is a minority view that limiting this intervention to standard consumers does not deliver a level playing field between large DG and small DG. Whilst large DG have negotiated contracts and EDBs should reward for the avoided cost of distribution, there was a concern that the large DG connecting parties do not have an equal negotiating footing when they have no choice but to contract with the network at that location and that limited ACOD payments in the market to any parties not related to EDBs is, prime facie, a cause for concern. We note the Authority has other workstreams looking at distributed generation connection and networks have work to streamline the connection process (including visibility of information) and have not reviewed how this work may mitigate this concern. *We note the consultation papers provide appropriate opportunity for comment.*

- **The group felt there was insufficient initial clarity of the problem definition and that the cost benefit analysis for network injection rebates is not sufficiently robust (2a).** A strong opinion of some members is that the problem was not sufficiently defined and analysed, that the proposed pricing approach is not sufficiently targeted to underlying peak needs (2a) and the cost benefit analysis is not sufficiently robust (for instance not comparing different pathways to the same outcome). We note that the financial analysis focuses on the assumption that the primary benefit of intervention is to encourage more investment with a better financial return to consumers. Many consumers invest in distributed energy resources for reasons other than financial return. The impact and effectiveness of tariffs needs to be assessed through the lense of how consumers are engaged with the opportunity to use, and are rewarded for using, their assets in a way that meets their primary preferences and also delivers beneficial system outcomes These concerns are informed by the international experience of unintended consequences following the use of feed in tariffs. We note that for all of three of the proposals our working sessions with the Authority staff did not include specific contribution to, briefing on or review of the cost benefit analysis and other data presented in the proposals due to the nature of the timing of our work. Our reporting window does not provide for detailed review and collective discussion on these. *We note the consultation papers provide appropriate opportunity for comment.*

1.4. Key out of scope or observations of significance but not passing the materiality test

- **Some consumers can benefit from investment incentives targeted to highest value times.** The 2a and 2c proposals will tend to spread the value shared with consumers over many kWh, every day of the year rather than encourage targeted investment/ use. This can work well with consumer segments that favour habitual use (set and forget). The diversion of value in this way however may reduce the value stack/ incentive available to grow other solutions (e.g. VPP, aggregator or other contracted solutions) and therefore the ability – as well as funding available – to sign up consumers to higher value, locational and temporal uses. The consequent inability to access sufficient value may have unintended consequences on competition in and from new entrants in the distributed energy resource value network. In addition the "spreading" of this value across many kWh may not be sufficiently targeted to attract many DERs that are available to participate in daily injection. We note the 2a consultation paper indicates monthly values in the range of $8-20 for a 10kWh battery system but also on some networks that value can be lower. Appendix 2 provides an example showing an annual rebate of $88 only for a 10kWh battery system in a large EDB with peak rates only applying for the 5 winter months on weekdays. We recommend separate Authority work to consider how to better segment consumer behaviour, enable relevant consumer segments to access and benefit from the system savings where injection is targeted at specific locations and times of high value constraint. The work should be done alongside other agencies and organisations that can influence relevant price and non-price incentives. We note the consultation covers network demand charges that may be used as part of a more targeted approach and does not preclude the growth of VPP or aggregator services. *We note that the consultation does provide for feedback on the balance between price-based and contracted flexibility.*

- **Past experience with distribution pricing principles provides lessons on how to accelerate principles-based regulation, not a reason to by-pass it.** A strong view was expressed by some members that there are valuable lessons learned by both regulated networks and the Authority from the long time it has taken to implement the distribution pricing principles and that these lessons provide a basis for much faster implementation of future changes in a way that matches consumer needs and network value.

- **Distributed generation owners believe themselves disadvantaged by other (locational) pricing factors not in this scope.** A minority view identified that a significant factor that erodes consumer value and investment is that network costs charged to consumers are the same regardless of how far and how much network is used in delivering that electricity. The absence of local pricing (e.g. a local bus ticket) for highly localised power is counter intuitive to consumers using only a fraction of the system and undermines the perceived inherent value of local generation. Innovations like MTR and peer to peer do not resolve this if "national" transportation or lines charges are still applied. In an extreme example, in 2 phase homes (that in some parts of the country are required/ encouraged by networks) a consumer can *instantaneously* be forced to sell their power for 12c/kWh and buy back at over 30c/kWh – the same second in the same home! We acknowledge this locational signal is out of scope of this intervention but that there may be a connection between this (perceived) consumer issue and the expressed consumer expectations informing this intervention. *The minority view is that either investment is needed to properly explain to consumers the underlying cost drivers or further work is needed on cost reflective distribution pricing principles.*

- **Recommendations to engage with existing experience and insights.** Members made specific recommendations to engage with customer segment and customer journey specific analysis, overseas experience, previous work (e.g. EPR) and insights from product offerings exploring new consumer offers (including those that have withdrawn from the market to avoid survivor bias). The sub-group has not had access to these engagements or specific insights.

- **System transition and timing perspective.** Differences of opinions within the sub-group reflected whether these measures were optimal in the context of the current DER landscape or how our electricity system would operate best operate in a world of high variable renewable energy and flexible, distributed energy resources. Our separate management letter sets out more detail on this.

1.5. Other matters

- There was a minority view expressed that the phrasing of the TOU plan design basis may risk unintended restrictions on new services for consumers. This can be addressed at the code definition stage but may attract some comment. Paragraph 5.9 states that TOU plans are ones that "Actively engages the consumer in load or export shifting– ie, plans that rely solely on load control by another party would not be consistent with the design basis". Whilst the intent here looks clear that load control by 3rd party is allowed within a plan where further active consumer engagement shifts more demand, and that the exclusion only applies where the plan will rely solely on load control by another party (e.g. not reward other changes), guidance will need to make this very clear. Any grey area could be exploited to limit emergent 3rd party services and consumer choice.
- A minority view expressed the risk that participants may use non price levers to reduce the potential growth in injection and offset the price signal. Non price levers could include connection rules, settings, equipment or sizing requirements. An indication of how rules or monitoring reduce this risk will be valuable.

2. Introduction to EAAG and the subgroup

The EAAG was formed in June 2024 by the Electricity Authority (Authority). Under its terms of reference, the EAAG is expected to use its knowledge and expertise to investigate, analyse, and make recommendations to the Authority on matters included in its work plan as appropriate to the work plan item.

The work plan is primarily developed for the group to provide advice on Authority project work and consultation papers before public release, and, as appropriate, to assist in considering and reconciling views presented in submissions, developed with regard to the Authority's budget, part of the Authority's overall work programme, priorities and timeframes and can be updated to account for developments that occur in the course of the Authority's overall work programme.

A key role of the EAAG is to use its collective knowledge and experience when considering the matters before it. The EAAG's advice to the Authority must be independent, considered, and supported by robust analysis. The quality of the advice must be sufficient to enable the Authority to make well-informed decisions.

The cost reflective tariffs subgroup is a working group of the EAAG that first met mid-September 2024 with reporting early December 2024. It was formed to assist with a specific pre-scoped Authority project.

The members in the subgroup are recorded in Appendix 1.

3. Context to and scope of our work

The EAAG was formed as the Authority wants and needs to work differently to provide the regulation needed for the systems transition through:

- working more closely and transparently with the sector and consumers
- covering a wide range of topics across technical areas, consumer interest and future perspectives
- using an advisory group early and often in our decision-making processes.

The form and function of the advisory group contributes to how the Authority works differently – specifically alongside diverse groups of stakeholders to develop well-informed regulation, quickly and robustly.

This is the first report using this new approach which seeks to deliver a balance between 1. robust independent expert analysis and recommendations and 2. agile, quick and efficient delivery.

The Chair acknowledges the role of the Authority staff and subgroup members in pioneering new practice and their work in its delivery.

With our limited agile work scope, this report is an independent summary to the Authority under the engagement conditions outlined. We report by exception on material matters where the consultation papers may

- not sufficiently reflect matters we have identified and/ or
- not provide opportunity for comment and/ or
- present a preferred proposal where the weight of the collective group have material concerns that a significant proportion of stakeholders will have high levels of concern relative to the benefits identified.

We also provide comment on substantive matters that arose in our discussions but are out of the current scope of work.

Our work does not provide for robust independent analytical review, research, investigation or solutioning steps that a longer and more deeply resourced programme may include.

3.1. Technical/ subject/ project scope

The cost reflective tariff project covered 3 discrete solution proposals where strawmen solutions were pre-scoped by the Authority.

Whilst the Authority and working group discussed the problem statements that informed the solutions, the working group scope was not to perform root cause analysis on the problem(s) or explore other pathways to address the problem(s).

3.2. Scale/ maturity of work

The project was mature in so far as there was 1) a discrete pre-defined solution for each of the 3 work areas and 2) a planned short, agile project to assess and input to the steps being taken by Authority staff as these were analysed.

3.3. Timeline and resources

This was a short agile project sprint with two workshops over 5 weeks providing input and 6 business days from receiving the Authority report to the work group reporting.

All analysis and documentation work were directed and managed by the Authority staff with no independent analysis commissioned.

3.4. Reporting on material matters only

This letter reports on matters the group assess as material for the intended user for the purpose of this scope. We acknowledge that there were discussions across themes of a less material nature but that can still be cumulatively significant to consumer investment in distributed generation (including storage) or supporting solutions (e.g. flexibility services).

3.5. Composition of the subgroup

The subgroup was selected in accordance with the Terms of Reference and a specific focus on having the required stakeholder insights and expertise within a small team to support agile work. The subgroup is not a proportionally representative group of stakeholders and so any reference to majority or minority opinions does not infer proportionality.

4. Approach to and nature of our work

- In performing our work, we have relied on discussions with Authority staff and the analysis/ papers prepared by the Authority staff or their consultants. The work has been staged so that the Authority staff can consider our discussions in their work as it is progressed.
- Our contribution is based on member experience and knowledge and, where appropriate considering the timing, resources and confidentiality, member generic insights from other stakeholders. This scope did not provide for modelling, research or other analysis independently of the Authority workstream.
- The approach was to provide collective expert advice with independent thinking at two key tollgates in the Authority work process through 1 to 1.5 hour workshops that targeted specific questions and needs identified by the staff, whilst providing limited time to discuss more broadly the information presented.
- With a short window and high cadence to the work and the expectation that Authority staff would further analyse this input as they progressed toward consultation documents, discussion focused on the diverse inputs of members rather than work through to a single collective voice or opinion (on a more limited range of matters).
- With the preparation of the Authority's draft documents, the subgroup has considered where there are collective, majority and minority perspectives and key drivers on material matters to this report.
- The Authority Representative has provided secretariat resource to capture the record of our discussions and for the preparation of this letter, alongside the Chair.

5. Reporting party

The Cost Reflective Subgroup of the EAAG is providing this report in accordance with the request from the Authority to report to the Authority.

This is a stand-alone project and not part of the wider work plan of the EAAG.

Chair

Jamie Silk

Chair of Measures To Improve Price Signals For Distributed Energy Resources Sub Group

Appendix 1 Members

The subgroup was comprised of the following members, selected as per the EAAG Terms of Reference:

- Jamie Silk (Chair)
- Fiona Wiseman
- Huia Burt
- James Tipping
- Jason Larkin
- Ryno Verster

Deborah Hart resigned from the EAAG and the subgroup prior to the completion of the Authority proposals and before the preparation of this letter.

Appendix 2 Member provided example of consumer rebate levels

Appendix 2 provides an example of consumer rebates showing an annual rebate of $88 only for a 10kWh battery system in a large EDB with peak rates only applying for the 5 winter months on weekdays. This is shared to supplement the examples provided in the consultation paper with an additional EDB pricing setting. The members have not reviewed or validated the examples on the consultation paper.

Solar 6kW + battery 10kWh (~ two peak discharge cycles, small peak PV injection, use of battery for peak load)

Fixed charge	365	1.4300	522		
peak	0	0.0983	0	Consumption kW	2000
off-peak	2000	0.0000	0	HW Control %	40%
controlled	3200	0.0162	52	Peak consumption	0%
peak injection	1788	-0.0492	-88		
off-peak injection	8000	0.0000	0		
			486		

Solar 6kW + battery 3kWh (~ two peak discharge cycles, small peak PV injection, use of battery for peak load)

Fixed charge	365	1.4300	522		
peak	0	0.0983	0	Consumption kW	2000
off-peak	2000	0.0000	0	HW Control %	40%
controlled	3200	0.0162	52	Peak consumption	0%
peak injection	262	-0.0492	-13		
off-peak injection	8000	0.0000	0		
			561		

Management letter

To the Chief Executive and the Authority's Representative to the Electricity Authority Advisory Group

Background

The EAAG was formed as the Authority wants and needs to work differently to provide the regulation needed for the systems transition through:

- working more closely and transparently with the sector and consumers
- covering a wide range of topics across technical areas, consumer interest and future perspectives
- using an advisory group early and often in our decision-making processes.

The form and function of the advisory group contributes to how the Authority works differently – specifically alongside diverse groups of stakeholders to develop well-informed regulation, quickly and robustly.

This letter follows our first report regarding our engagement with the cost-reflective pricing and tariffs initiative, which used a short, fast paced and light touch approach to deliver a balance between 1) robust independent expert analysis and recommendations and 2) agile, quick and efficient delivery.

We are pleased to have had the opportunity to pioneer new practices in this subgroup that will help the Authority realise its ambition and believe the engagement has been valuable in shaping a better and well-informed consultation proposal within the constraints of the engagement scope.

Experience for management attention

Through our pre-consultation work on the Measures To Improve Price Signals For Distributed Energy Resources, the Sub Group identified several matters to explore that we believe can improve the impact of our and the Authority's work.

These matters are not addressed in our report letter as our opinion is that they are not material matters to the Board decision on that work (e.g. will not be a deciding factor in that decision). They are of significance to the quality of the independent, robust and expert advice on future work the Authority will progress.

We recognise that both the 1) ongoing work to develop high impact engagement between the Authority and the recently established EAAG, and 2) the continual development of the Authority's own work processes, are already progressing some of these themes. This letter provides empirical insight to contribute to that work.

We note that as we iterate and mature these processes, we anticipate the opportunity to simplify and focus our reporting to the Board.

A. Matters of strategic framing and approach (outside the EAAG scope)

Our work highlighted elements of strategic framing or context that could enable better and faster analysis, deeper insights and more alignment across stakeholders.

1) **System transition perspective:** varying opinions within the sub-group reflected differences of perspective in whether the measures were being assessed in the context of how our electricity

system operates now or how it could best operate in a world of high variable renewable energy and flexible, distributed energy resources.

a) These tensions impact 1) assessing the appropriate measures to take and in what sequence, 2) how durable incentives may be and the risk of "unwinding" them as markets change and 3) the appropriate way to monitor the impact of measures.
b) A shared vision or reference point for our transition pathways and a high level roadmap of the changes projected can help frame an understanding of the appropriate timing, sequencing or magnitude of interventions.
c) EA framing work setting out a high level blueprint for the energy transition with a system lense can assist focus Advisory Group contributions. We anticipate the EA would complete this in partnership with other agencies and organisations.

2) Recommendations to engage with existing experience and insights: members made specific recommendations to engage with customer segment- and customer journey-specific analysis , overseas experience (noting we start from a different place to, for instance, Australia), previous work (e.g. EPR) and insights from product offerings or projects exploring new consumer offers.

a) Some of this contextual work may be better framed independent of a specific initiative and then adapted or deepened for specific needs. For instance, customer segmentation and high-level journey mapping is a useful tool to inform multiple aspects of the Authority work and could make a valuable contribution to root cause analysis, prioritising customer needs and understanding the intended/ unintended consequences of actions.
b) We note when considering the needs and experience of customer segments (and other value chain participants), there are benefits from including those that have withdrawn from the market in recent years to avoid survivor bias.

3) **Recommendations to consider consumer education and information with the energy transition:** the way we have viewed energy education for consumers and energy efficiency has not kept pace with the emerging transition. Two themes stood out that in our view warrant further action.

a) First, consumers buying DERs are making a complex decision in some parts influenced by personal preferences for sustainability, efficiency, resilience or other product features but that is also in some part a financial product. As prices trends or relative prices across the day or seasons change in future, the financial return from solar, battery and EVs will change. More information should be available to help understand that decision – as is the case with some financial products.
b) Second, when consumers use power (time of use) is becoming a significant value driver, but there is still limited information assisting consumers with this alongside energy efficiency. We recognise that the work to replace Powerswitch will provide additional support for consumers.
c) We recommend that this imbalance is addressed across multiple agencies and industry partners as a first step to enabling flexibility.

B. Matters of process within the scope of the EAAG

Our comments here are provided in the context that:

- the cost-reflective pricing engagement was a short agile project sprint with two workshops over 5 weeks providing input and 6 business days from receiving the Authority report to the work group reporting on the recommendations;

- all analysis and documentation work was directed and managed by the Authority staff with no independent analysis commissioned;
- we were engaged early in the Authority analysis of the proposals under review;
- the scope covered specific strawman proposals but not the problem definition or root cause analysis. The scope did not therefore consider the existence and/or extent of the problem, or the best way to address the problem, rather focusing on advice regarding the implications of, and opportunities to refine, the specific solutions proposed;
- some of our engagements will be with projects that have progressed beyond their early definition phases; and
- with the need and opportunity to do things differently and in multiple forms of engagement, the Chair and Authority Representative will be actively prototyping and developing the engagement framework.

We recognise that the EAAG will be engaged at multiple different stages and maturity of the Authority's work at different times. These comments share the experience from this sprint of work to help inform future planning of different types of engagements and acknowledge the risk-reward trade-offs for management, the EAAG and the Board.

In particular the insights can help inform the advance scoping of particular engagements, the communication of those scopes and expectations (such as through the newly implemented engagement scoping outline or more formal engagement letters), the overall planning around how the EAAG may be engaged through a project's lifecycle and the under development tools that assist Authority staff, EAAG members and the Board to understand the risk-agility/ project maturity profile of an engagement.

1) Timing of Subgroup Engagement

i) Context

(1) We were engaged on a proposal where a specific intervention had already been identified by the Authority. We were not engaged at problem definition and in root cause analysis.

ii) Implication

(1) Our letter to the Board sets out risks and alternative approaches that we believe would have delivered value in exploring at the problem definition and root cause analysis stage of the work. We recognise that as a new group, and as the Authority has an existing work programme, we will be engaging on a number of already mature projects.

(2) Our letter to the Board sets out an example of where stronger linkages between different Authority work streams and identification of how these intersect, or have dependencies, may have assisted in framing this work.

iii) Recommendation

(1) Future work planning provides for an appropriately scoped engagement stage for problem definition, evidence gathering and root cause analysis that can provide earlier guidance regarding the scope and focus of the proposed initiative. This is where testing and information provision by sector experts can provide considerable value.

(2) The Authority consider how EAAG insights may contribute an additional perspective for the Authority on the interdependencies across, and sequencing of, the work programme.

iv) Current action and proposed

(1) The Authority Representative and the Chair are engaged with management to explore the appropriate staged engagement process to deliver value at the project definition phase.

(2) The Authority Representative and the Chair are working with management on the nature of engagement at the time of strategy setting and work programme development.

2) Clarity in balancing early touch, agility and the need for informed, robust advice

i) Context

(1) The duration of the engagement was short, fast paced and limited in scope minimising the capacity for informed, robust advice in the form that recent Advisory Groups have worked to.

(2) We were engaged on a proposal where a specific intervention had been identified by the Authority for discussion but before data (appropriate to the maturity of the proposal) was available to us.

ii) Implication

(1) We are pleased to be able to support the Authority to develop well-informed regulation, quickly and robustly. The engagement has provided useful insights on how we can do that well.

(2) There is a clear risk-reward trade-off for the Authority as it sets the scope and nature of each engagement and therefore the capacity to deliver advice. It is important to the use of, and efficiency in performing, our work that we manage this transparently as different scopes target different levels of engagement, available information and maturity of analysis.

(3) Being data-informed (appropriate to the scope and maturity of the work) can be very powerful to help members reconcile different perspectives and deliver more useful insights to the Board.

(4) Our letter to the Board sets out the limitations in this scope and, as a result, to our advice.

(5) Our commentary in our report is expected to become more direct, concise and useful for its intended purpose as we mature the framing and communication of this trade-off. This will be informed by further experience across different levels and types of engagement.

iii) Recommendation

(1) We prioritise maturing our processes and tools to assist members, Authority staff and users of our work to understand the positioning of engagements. This will inform how we execute work and the intended user of reports about the risk – agility/ maturity trade-off appropriate to the scope.

(2) We work to align available data and insights appropriate to the scope and subgroup engagement in a timely way

iv) Current and proposed action

(1) The Authority Representative and the Chair have agreed with management a suite of actions to add greater clarity to assignment scopes and to develop a risk- agility/ maturity framework and tools to assist members, Authority staff and users of our work. The first of these developments has been implemented with the latest sub group.

(2) The Authority Representative and the Chair will be working toward integrating appropriate practices to support earlier data based decision making whilst balancing the value that early engagement can bring.

Ngā mihi nui

Chair

Jamie Silk

Chair of Measures To Improve Price Signals For Distributed Energy Resources Sub Group of the Electricity Authority Advisory Group