D'SOUZA
ASSOCIATES

7 May 2025

Rob Bernau,

Energy Competition Task Force Programme Lead,

Electricity Authority,

By Email: levelplayingfield@ea.govt.nz

Consultation – Risk Management Options for Electricity Retailers

Dear Rob,

Thank you for the opportunity to provide the Electricity Authority (EA) with feedback on this matter. I firstly want to acknowledge that the outcome of this process requires a difficult *balance* between the competing interests of the varying stakeholders *and* the *political* requirement for urgency.

Being a non-technical observer of the electricity sector, I have sought to apply my professional background in NZ financial markets [1] (including as a regulatory standards-setter in audit and financial accounting), to analyse and infer efficient regulatory solutions to the current situation.

After initially seeking to explicitly respond to the scope of this consultation, I came to the conclusion that a Whole-of-System (Holistic) Approach offered a far superior solution = rather than the targeted scope of this Consultation.

This extended to the need for *explicit* standardisation of retail margins **and** preferably the independent, verifiable assurance of these margins.

The principal recommendations in my submission (*in descending order of significance*) : are that the EA needs to -

1. **Apply** a Whole-of-System outcomes orientated approach to *optimising* total delivered energy costs to consumers.

[1] Refer ***D'Souza Associates*** Profile page 25.

2. **Agree** with MBIE and the Commerce Commission the common economic measures and criteria for the evaluation of the cost-benefits analysis across the total delivery system.
3. **Implement** an independent assurance regime for a selection of key measures (*including retail margins*) to address the widespread *perception* that the existing regulatory framework is being gamed by several participants with market power.
4. **Rectify** the *pre-identified* inconsistencies in the Code in a more *timely* manner and be consistent in the application of the pricing principles in the generation and network segments of the market.
   - Noting that some inconsistencies are policy and not regulation.
   - Also that ***most of the smaller EDBs arguably do not have the capability or the critical mass to transition into an electrified environment.*** [2]
5. **Standardise** the definitional settings for Distributed Generation connection assets. I believe this to be the key *regulatory* area with the ***greatest impact*** that would improve many of the issues impeding the market.

The submission is segmented into the following Sections

[2] In the current "electrification" environment where the Regulated Asset Base is being technologically disintermediated at rates above the allowed deprecation rates.

[3] Price Discovery in a Renewables-based electricity System – 11 December 2024

Given I am [redacted] based, I would welcome the opportunity to discuss the contents of this submission with the Electricity Authority if required.

Finally I pose the question :

" Does the Electricity Authority feel that as a group, they have the appropriate skills at the Board level to recognise, solve and manage appropriate solutions in a rapidly transitioning environment? "

Yours sincerely,

[redacted]

Clyde D'Souza

Conflict Declaration

I'm a retail customer of Mercury Energy.

This submission is "self-funded" but I have also engaged with a number of market participants to "sense test" the views expressed in my submission.

The views expressed are wholly my own.

1.0 List of Recommendations

Recommendation	Description	Section	Page	Type	Impact	Urgency
1	Whole of System Approach	2	9	Framework Structure	High	High
2	Tri-partite Coordination	2	9	Framework Structure	High	Medium
3	Standardisation	2	9	Regulatory Clarification	High	High
4	Competitive Neutrality	4	16	Regulatory Application	High	Maintain
5	Distributed Generation	5	17	Regulatory Policy	High	High
6	Connection Assets Definition	5	18	Regulatory Definition	High	Maintain
7	Incremental Cost	5	18	Regulatory Definition	High	Maintain
8	Vesting Survey	5	19	Procedural	High	High
9	Vesting Reversal	5	19	Regulatory Definition	High	High
10	DG Term Standardisation	5	20	Regulatory Clarification	High	High
11	Retrospective Prohibition	5	21	Regulatory Clarification	High	High
12	Cost Allocation Equivalence	5	21	Regulatory Definition	High	Medium
13	Transpower Common Cost	5	21	Regulatory Maintenance	High	Maintain
14	Non-network Solutions Promotion	6	22	Regulatory Policy	Medium	Medium
15	Non-network Solution Counterfactual	6	23	Regulatory Policy	Medium	Medium
16	Non-network Solution Decision Transparency	6	23	Regulatory Policy	Medium	Medium

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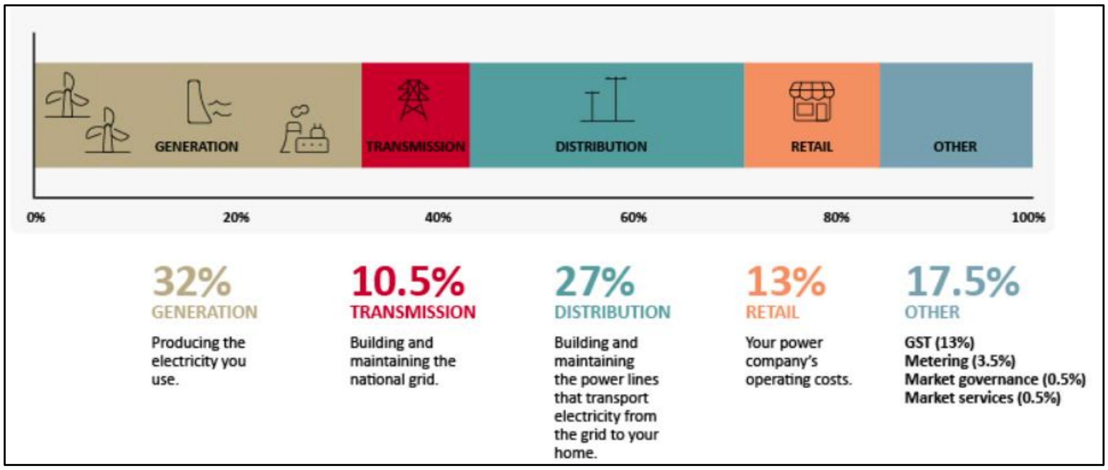
Recommendation	Description	Section	Page	Type	Impact	Urgency
17	Retail Margin Definition	7	23	Regulatory Policy	High	High
18	Independent Assurance	7	23	Regulatory Policy	High	High
19	EA Board Composition	7	23	Regulatory Policy	High	High
20	Non-Assurance Justification	7	24	Procedural	Medium	Low
21	Disclosure Simplification	7	24	Procedural	Medium	Medium
22	ACOD Benefit Review	7	24	Procedural	High	High

2.0 Whole of System Approach to Management

2.1 Consumers **don't** review their power bill as the sum of the individual, unbundled components, ***but as a total nominal cost***. **Figure 1** below illustrates the relative components of a retail consumer power bill – prior to the 1 April 2025 increases in regulated prices for both the transmission and distribution networks. It illustrates how the cost of Generation (32%) and Distribution (27%) contribute the greatest proportion of a retail consumer's energy bill. This indicates how (with Distributed Generation and Non-network Solutions) these components ***offer the greatest economic opportunity*** for a system wide optimisation thereby delivering lower ***aggregate*** energy costs.

Figure 1 : Distribution of Average Household Power Bill (31-3-25)



Source : **Commerce Commission**

2.2 Put simply, the estimated $32 billion in estimated *incremental* investment projected by the Boston Consulting Group [4] in their "Decarbonisation Roadmap for New Zealand's Electricity Sector", is highly likely to be at least partially avoidable and possibly *significantly lower*. *Arithmetically quantifying this opportunity; a 5% saving on the $32 billion in incremental investment at the 7.9% regulated WACC equates to a potential saving of $126.4m p.a. in consumer electricity costs.*

2.3 A significant sub-class of the 29 distribution entities do not have the operational, financial (for their share of the incremental $22 billion), or corporate governance capability to deploy this investment effectively in *the requisite time frame*. Nor should they be allowed to do so. In FY24 the Electricity Distribution Businesses regulated asset base was $17.2 billion. This indicates the incremental investment quantum represents 128% of the baseline. Additionally the Auditor General's Office has

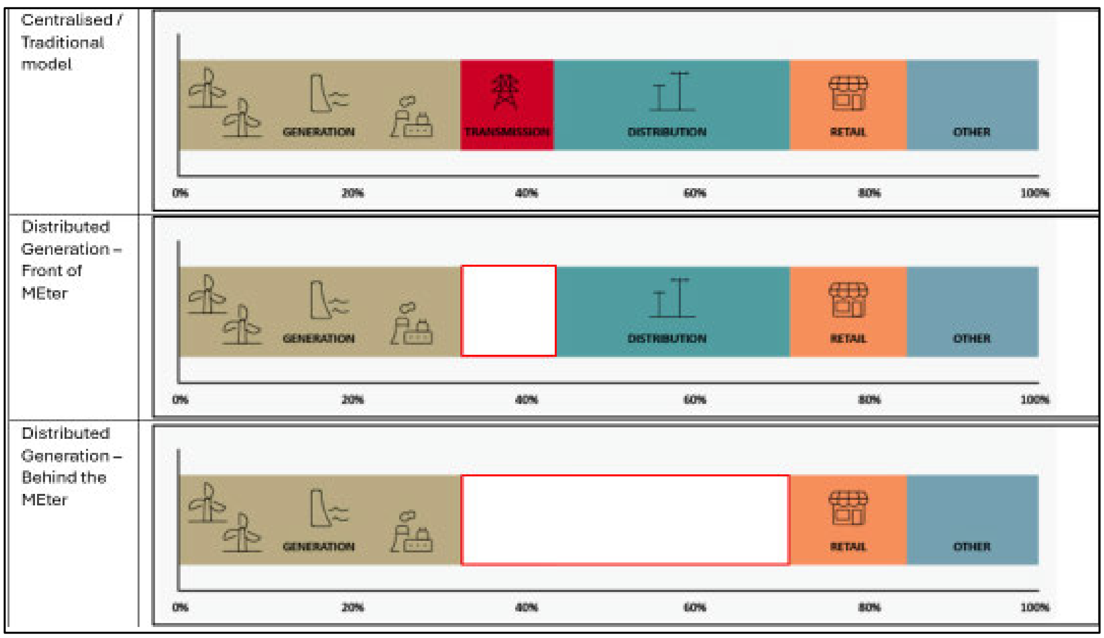
[4] Being $8.2 billion for Transmission and $22 billion for Distribution.

expressed doubt [5] on Transpower's ability to operationally manage its agreed capital and operating expenditure schedules.

2.4 The significant nominal, *aggregated* cost increases (over 5 years) across the Transmission (44%) and Distribution networks (47%) thus **impacts 37.5%** (43% excluding GST) of the average household power bill. Variable energy costs would therefore need to arithmetically decline by 54% to offset the regulatory permissible rises in Transmission and Distribution costs.

2.5 The following graphic illustrates the "addressable market" for Front-of-Meter and Behind-the-Meter Distributed Generators. Clearly Behind-the-Meter solutions are going to be an increasing focus with BESS being a disproportionate component as Distributed Generators "backfill" existing investments.

Figure 2 : Distribution of Average Household Power Bill (31-3-25)



Source : **D'Souza Associates**

2.6 **Conclusion : ** My view is that a **step change in approach is required for the deliverable economic efficiencies to be found in Distributed Generation, particularly BESS, are to be achieved.** This conclusion appear similar to the 11 December 2024, Market Development Advisory Group's Final Recommendations Paper – Price Discovery in a Renewables-based Electricity System.

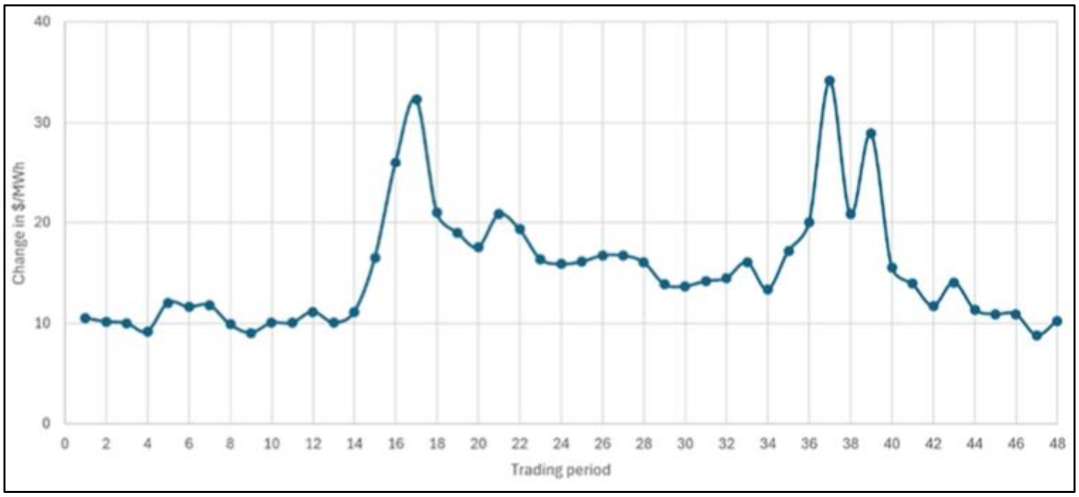
[5] Parliamentary Scrutiny Week 3 December 2024.

Whole-of-System Benefits Example

2.7 **Figure 3** presents the *annual average* price elasticity for a 1% change in demand during a day (in 48 half hour segments) for the year ended 30 September 2024. It illustrates that:

- During the breakfast and dinner demand peaks, the price sensitivity *more than doubles* to +$30 per MWh.
- Between 9 pm and 7am, the price elasticity is ~$13 MWh.

Figure 3 : Annual Average Intra-day Price Sensitivity of Demand (YE 30-9-24)



Source : **Statement of Issues - Proposed Manawa Energy Takeover (5 Feb 25) – Pg 68**

2.8 Contextually it is also worth noting that :

1. As an annual average, it ***masks seasonality***. Winter demand price sensitivity is understated and summer overstated. *The potential economic saving to consumers from* a *reduced winter demand sensitivity* would be greater.
2. It is **highly probable** that overall demand sensitivity has been on an ***ascending*** trend as the system's reliance on renewable firming generation has increased.
3. The intra-day peaks have been rising and are likely to rise [6]. *Which should not have been removed by the EA.*
4. It is **only** calculated for a 1% demand change – a *5% demand shift* might be more appropriate ?
5. It excludes significant i*ncremental* variable energy cost benefits to consumers from the prioritisation of a ***system wide*** optimisation as a policy approach.
6. Contact Energy's response to the graph shows that the average is highly <u>reliant on a few outlier events</u>, and that the median result shows a more even elasticity over the day.

[6] E&Y Literature Review February 2023.

2.9 The adoption of demand shifting policies would also be evidenced as an **outcome** – by the flattening and reduction in price sensitives to demand changes. The total economic benefits would also extend to the networks and generation, and ultimately retail prices.

Sub-optimal Grid Investment - Australia

2.10 In Australia, there appears to be no overall government strategy plan or policy charged with assessing the overall system trade-offs between large, designated Renewable Energy Zones (centrally planned grid infrastructure) and a more Distributed Generation plus Non-network solutions alternative of equal scale of investments which is the energy + infrastructure cost benefit case for consumers.

2.11 The absence of a holistic assessment of an integrated transmission capacity plus distributed generation assessment, recently stranded some of Australia's best wind generation projects with no grid access. [7] These zones were rated [8] for specific maximum output capacities that under-rated the wind resource (at sub-optimal capacity factors less that 30% rather than the required capacity factors greater than 40%). Simultaneously, the network transmission capacity was capped at a level too low for the generation resource – being a 330kV transmission line rather than a 500kV line. As a consequence there is not enough grid capacity to unlock many of the best projects in the region from Balranald to Hay and Buronga.

Recommendation 1 – That the EA apply a Whole-of-System approach to their current narrow scope cost / benefit investment analysis for ACOT / ACOD as soon as practicable.

Recommendation 2 – That MBIE, the EA, and Commerce Commission agree on common economic measures and criteria for the evaluation of cost-benefits across the total delivery system.

Recommendation 3 – That the EA adopt industry standard methodologies and processes.

[7] The south-west renewable energy zone in New South Wales.
[8] By the Australian Energy Market Operator's Integrated System Plan.

3.0 Ohms Law – Technical Implications

3.1 Ohms Law [9] provides the relationship between Resistance and Voltage indicating how lines losses (resistance) and capital investment [10] can be minimised. It is thus the conceptual framework that has shaped my views.

3.2 Simplistically, **Distributed Generation provides the highest impact solution in a holistically managed system** as it minimises electrical resistance and the *net* capital investment required to deliver electrical energy to the consumer**.** This is because electrical resistance :

1. Accumulates with distance – thus favouring distributed generation with its demand load closer to the consumer.
2. Reduces at higher voltages due to the lower the current (thus favouring Transmission over Lines networks). Thus transmission lines should experience lower line losses per km of circuit length.

3.3 This implies that there are intrinsically greater potential savings at the network distribution level due to the lower voltage operating rates and <u>significantly greater</u> linear distances covered. [11] and the higher invested capital base.

3.4 Additionally Distributed Generation reduces *voltage fluctuations* which cause electricity transfer inefficiencies that result in squandered energy requiring power correction to maintain power quality (VAR) [12] **.** This currently has to be supplied <u>by generators at a system cost</u>.

3.5 Thus reducing the frequency and amplitude of intra-day voltage fluctuations by smoothing the demand profile, reduces resistance lines losses.

1. Thus making the removal (and subsequent reinstatement) of Regional Coincident Peak Demand charge on 1 April 2019 appear puzzling.
3. Higher network capacity utilisation rates are by definition more efficient and thus resistance is lower during the morning and evening demand peaks when the utilisation rates are high. This indicates that filling the demand troughs has clear *operating efficiency* benefits (direct energy costs).

3.6 I note that these network benefits were recognised (and graphically illustrated below) in the "Updating the Regulatory Settings for Distribution Networks Issues" by the EA in December 2022.

Question 1 : Given this graph was reproduced from a Sapere Report dated July 2020, I pose the question why the application delay?

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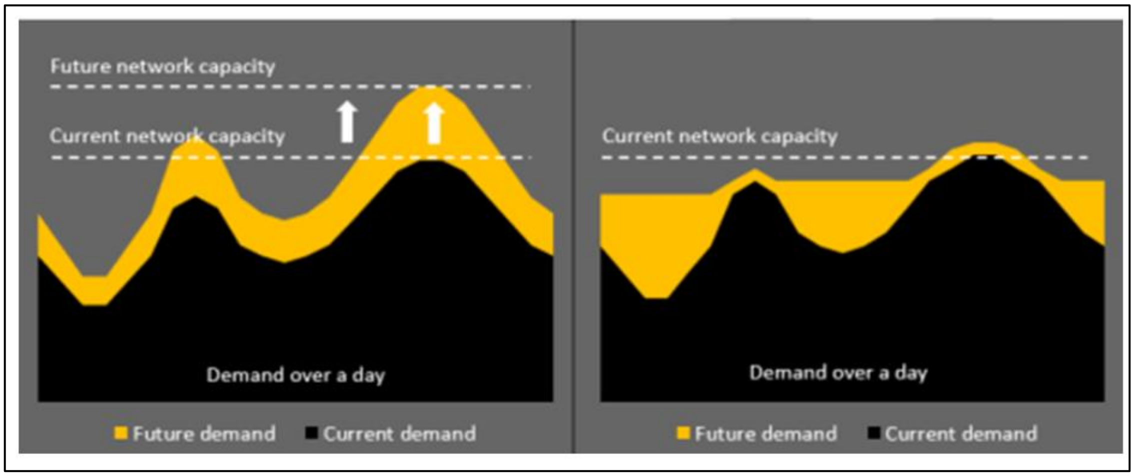
[9] Noting that my Physic knowledge ended in 1978 with a C+ in University Entrance.

[10] Through avoidance, deferral, quantum (ACOT & ACOD) and optimization.

[11] In FY24 there was 159,163 km circuit length for Distributers versus 11,803 km for Transmission.

[12] Volts Amps Reactive (VAR).

Figure 4 : Controlled versus Uncontrolled Future Demand



Source : **EA Issues paper on Distributed Networks December 2022 (pg. 11)**

3.7 The objective of nodal locational pricing at each local GXP was to signal transmission losses and future constraint costs, by incentivizing new generation to locate nearer to higher nodal priced GXPs.

Question 2 : **Have further studies been undertaken by MBIE or the EA to determine the generation and transmission locational cost-benefit relationships between nodal congestion pricing and accessing the highest value renewable resources?**

Trend in Transmission & Network Lines Losses

3.8 Lines losses are a hidden and **unavoidable cos**t to all consumers that are <u>network or grid connected</u> – at both the unit energy price and capital charge levels. Most consumers would however be unaware that the cost of lines losses are absorbed into their lines charges. **Figure 5** presents the 10-year trend in Transmission and aggregated Distribution lines losses. For context, net generation grew by 2% over the period.

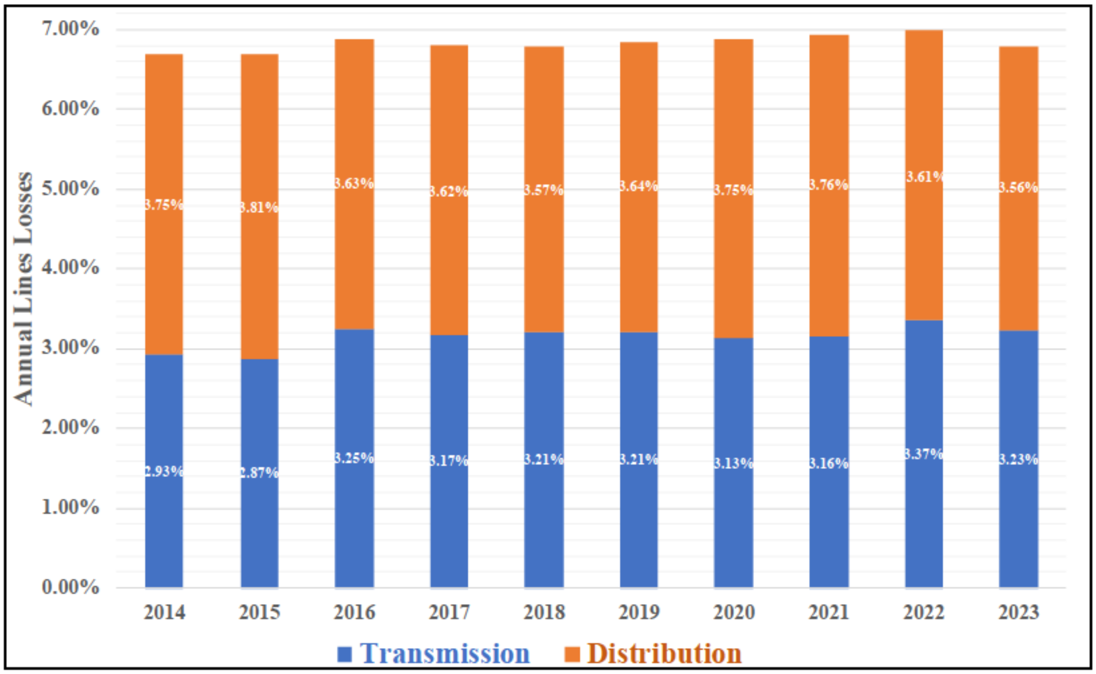
1. In 2023 they represented **6.79%** of the 43,494 GWh generated with Transmission losses representing 3.23% and Distribution representing 3.56%.
2. Transmission lines losses grew 12.4% over the period indicating ***reduced efficiency*** over the same period. They also show a steadily worsening trend.

   Question 3 : **Why? This appears to be counter intuitive.**

3. This highlights the economic sensitivity of this embedded cost to the underlying price environment.

4. Distribution lines losses fell by 3.3% over the 10-year period to 1,547 GWh or 3.6% of the energy transmitted. This equated to ~$40m at a retail margin of $20 per MWh.

Figure 5 : 10-year Trend in Annual Transmission & Distribution Lines Losses (CY)



Source : **MBIE Quarterly Electricity Data Tables**

3.9 Assuming one-third (225 percentage points) of the 6.79% of the aggregate lines losses are *potentially avoidable* through a system-wide approach at a *retail price* of 25¢ per kWh (excluding GST), this equates to $24.6m in avoidable costs to the consumer.

3.10 This calculation also highlights how the dollar value of the inherent losses ***scales with the energy price*** and both correlate highly in scale with peak demand periods. Prior to the dry year risk event in July 2024, listed Gentailers like Genesis Energy and Contact Energy were referencing Levelized Energy Costs of ~$85 per MWh real for base load which has now increased to an LCOE of +$125 per MWh.

3.11 Given retail consumers are mostly on fixed price contracts around the **$215 per MWh** (the demand weighted average wholesale spot price for the 12-month to 1 April 2025), Retailers will either be absorbing losses or looking to reprice their customer contracts upwards to offset this difference.

3.12 **Ohms Law** raises the following in-principle conceptual anomaly about **Figure 5.** Transmission losses *should be **significantly lower*** than those experienced by the Distribution networks because they are high voltage with a significantly shorter circuit length.

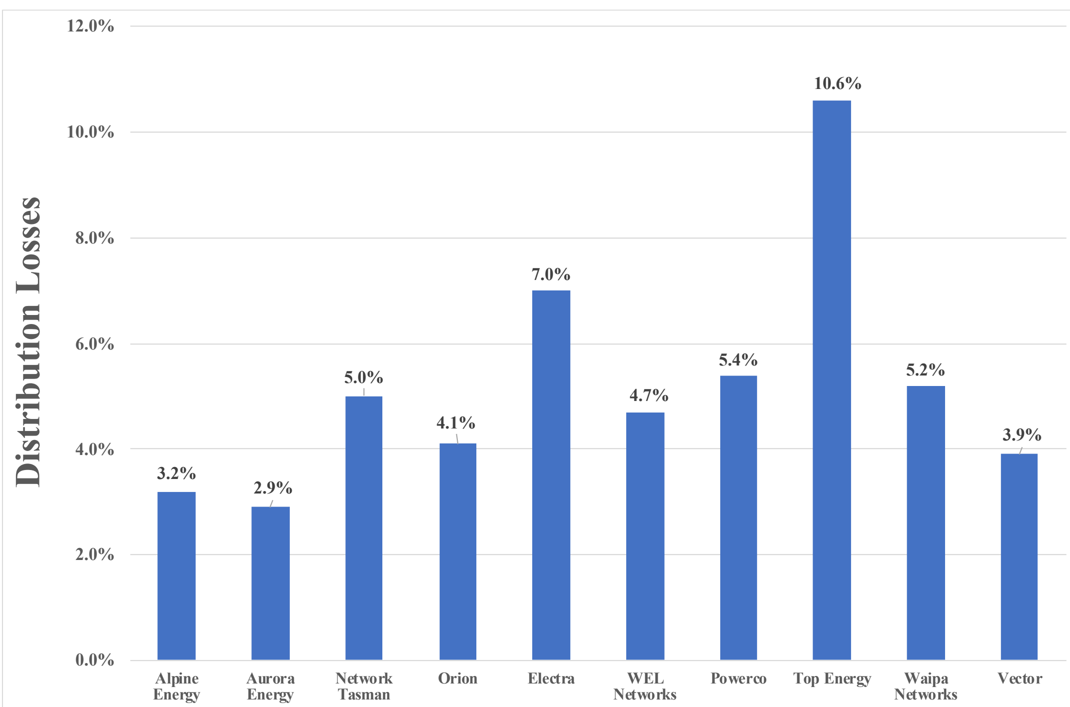
Question 4 : Why is this the case? Are transmission demands "peakier" than the lines networks, or are their overall load factors greater, or voltage / amperage ratios more limited? Is it a function of the N – 1 objective ?

Question 5 : Has the EA recognised the situation of **increasing transmission and network losses, particular in future forecasts of system losses with much greater electrification demands from electric vehicle charging?**

Question 6 : Why did Transmission losses deteriorate while EDBs improve? Is there a better business case for more local DG and Non-Network solutions, rather than more transmission and non-grid solutions?

Question 7 : What could the lines loss rate become if a Whole-of-System approach were adopted? A review of recent distribution system information disclosures highlights there may be a lot of economic potential for application of non-network solutions rather than increasing transmission system capacities.

Figure 6 : Comparative FY24 EDB Lines Losses



Source : **2024 PWC Electricity Compendium – Pg 14**

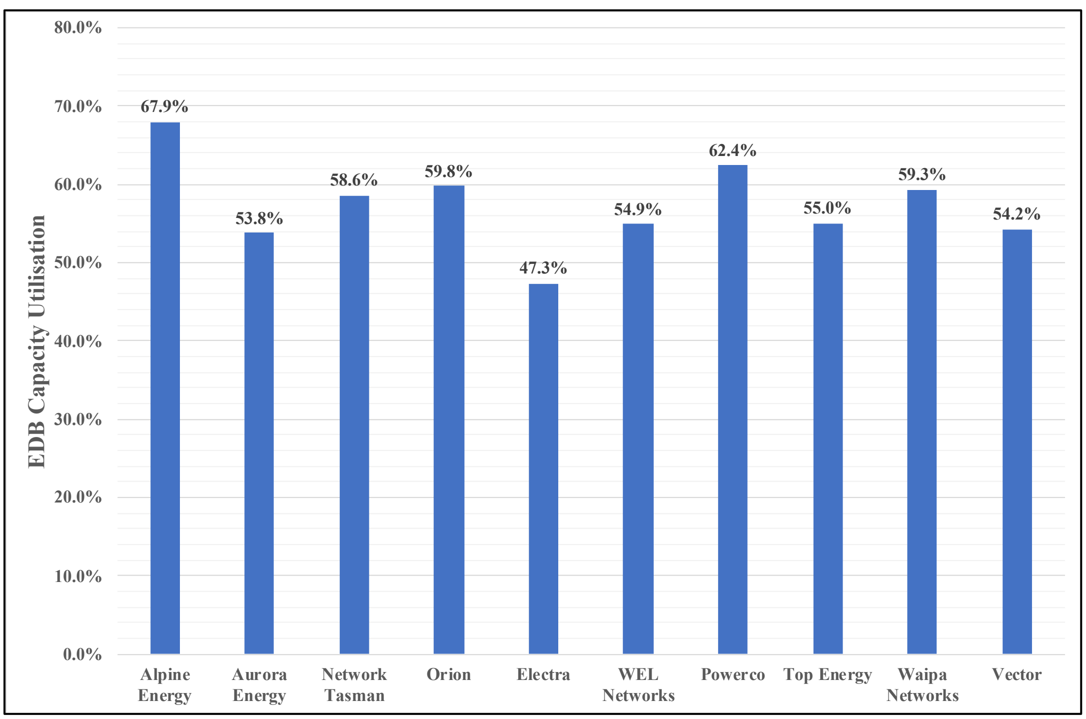
3.13 The previous figure compares the lines losses for a selection of EDBs. We note that the range is exceptionally wide (at 10.6% for Top Energy to 2.9% for Aurora Energy) with the average at 5.5%. Given the prior discussion, it is logical to infer that the EDBs provide the greatest nominal and proportionate opportunity for optimising investment with a systems-wide approach.

3.14 Clearly Top Energy's poor lines loss performance is a function of its distance from generation, low ICP density along its circuits, and the disproportionate length of its circuits.

3.15 **Figure 7** compares the network **Load Factors** for a selection of EDBs. Note that the range for the EDBs is from 44.6% for EA Networks to 79.3**%** for Westpower. The average EDB utilisation was 58.6%. They indicate significant underutilisation during day and late at night into which load could shifted to manage greater demand peak or higher overall demand over time.

3.16 This suggests a regulatory initiative to establish an industry level optimum KPI and load factor for distribution networks. This target could then align with business case parameters for applying DG plus Non-Network solutions – including Distributed System Resources and Batteries, to *improve* the methodologies for the most efficient regulated investments?

Figure 7 : Distribution Network Load Factors (FY24)



Source : **2024 PWC Electricity Compendium – Pg 14**

4.0 Regulatory Conceptual Framework

4.1 The Electricity Authority have been statutorily charged "with promoting competition, reliability and efficiency in the electricity industry for the long-term benefit of consumers." To this we would also add that sound public policy requires:

a) **Competitive neutrality** – which particularly impacts distributed generation.
b) **Perceived** confidence that the Regulator was discharging its obligations in an economically efficient and fair manner across the *regulated* value chain. [13]
c) Transparent, predictable and evidence driven in approach to regulatory management.
d) **Non-retrospective** in the *financial* impact from significant changes – unlike the Transmission Pricing Model.
e) **Preferably** supported by an independently verified, *standardised*, monitoring framework.
f) **Regional consistency** without the arbitrary uses of network tariffs and pricing structures (access) to optimise individual EDB business objectives.

4.2 Competitive neutrality requires that all generation market participants need to be on a level playing field ***at all levels*** of plant scale and ***geographic location***. This enables natural market pricing advantages due to either location ***or operating flexibility***.

4.3 The Code should be competitively indifferent as to whether a "connection asset" is grid or distribution network connected.

4.4 A policy "least touch" approach should be preferred as it minimises economic friction costs [14] **and** the unintended consequences in a series of **inter-dependent** natural monopolies in order to reduce avoidable cost recovery.

4.5 Thus the structural vertical integration of Gentailers should be preserved **provided** the objectives of ***perceived*** retail pricing fairness and supply availability can be achieved.

4.6 All generation connections should be considered within a *dynamic system loading envelope* (a Whole-of-System approach), to ensure the power system can be optimised for **both** generation market and grid for network investment purposes. The key is to ensure that regulated price signals and non-network solutions contracts provide both Distributed Generation options *and* the appropriate incentives to manage peak periods.

4.7 I acknowledge that regulated price signals and NNS contract needs to substantially evolve to be investable. i.e. regulated price "signals" are a false investment signal – as the EDB can and does change pricing each year, it is not possible to invest with

[13] Reviewing the Risk Management Options for Electricity Retailers (27 February 2025) at 2.3.

[14] Review of the Economics Literature on the Pros and Cons of Vertical Integration and Vertical Separation in Electricity Sectors by Cognitus Economic Insights (Sept 2021).

confidence. Note also that C&I customers have no consumer protection from tariff change shocks.

4.8 *Default* system standardisation should be adopted <u>wherever practicable</u> with the:

- Default economic costs of the Grid or Network solution being available to all prospective market services suppliers.
- System performance demands, contract KPI's, and known constraints made clear and standardised across all Networks.
- Non-Network solutions should be offered term contracts *appropriate to the life cycle of the specific assets offered*.
- Networks being technology agnostic.

4.9 I observe that the *absence* of a "Rebuttable Presumption" that <u>clear</u>, default standards automatically apply **contrasts with the Reserve Bank's monitoring framework for regulated banks and insurers.** These regulatory, financial reporting and audit standards allow comparability between financial entities including segmental reporting. This would be useful for the *perception* of Retail Margins.

4.10 In my opinion, the <u>existing legislation</u> has not being effectively monitored nor enforced – specifically in Avoidable Cost of Distribution (ACOD) (more than Avoidable Cost of Transmission (ACOT). *This is particularly relevant as there appears to be a lack of Code clarity on assessing the benefits of ACOD.*

Recommendation 4 – That the EA explicitly follow their statutory objectives of promoting competition in, or the efficient operation of, or being competitively neutral in approach.

5.0 Distributed Generation

5.1 Distributed Generation may be defined as any form of generation connected to a distribution network, whether directly, indirectly or via a consumer's electrical installation. Distributed generation is thus *definitionally* more efficient in the provision of energy to a consumer as it :

- Is generally closer to the demand loads,
- Is developed as a specific response to a *consumer need* – either in price / quality / or availability,
- Consequently experiences significantly lower aggregate lines losses, and
- May avoid transmission service costs and the associated capital investment.

5.2 A Distributed Generator connected into an EDB network is definitionally limited by the available line capacity of the network connection ***unless*** it pays the incremental costs to upgrade the Network to get additional capacity. ***They cannot add incremental loading costs onto the Transmission Grid.***

5.3 ***A crucial differentiating element (and important policy consideration) between network and grid-connected generation is in the formers superior speed to market.*** This is particularly relevant at this juncture given the Gentailers (including Manawa Energy) appear to have limited financial or *internal* operational capability to accelerate their grid scale development programs. (**Refer 5.16**)

5.4 *To date*, Distributed Generation investment has been largely ignored by the electricity industry *despite* it being a more efficient supply option than larger scale central generation. This has mostly been at the expense of the potential benefits to both consumers from having lower energy transmission losses, lower peak traffic infrastructure demands and lower supply disruptions – an important consideration for food manufacturers. These benefits seems to have been largely ignored by planners and regulators in the New Zealand default code conditions.

5.5 This indicates that an outcomes orientated approach from the EA should **focus** on optimising the rules governing Distributed Generation as they offer the *greatest impact* on *accelerating* net generation development.

Recommendation 5 – That the EA address the root causes of the lack of Distributed Generation investment.

Battery Electric Storage Systems

5.6 Under the Code, Battery Electric Storage Systems (BESS) are deemed to be generators. In our opinion *they also provide the greatest immediate potential* for application into incremental generation capacity to maintain adequate supply margins to moderate elevated wholesale supply costs.

5.7 BESS can also potentially provide the following ancillary services:

- Instantaneous Reserves - both fast and sustained instantaneous reserves,
- Over-frequency reserves,
- Frequency-keeping, and
- Voltage support. [15]

5.8 In a dynamic rated network, it could supply to both the local demand and or export excess generation into the Transmission Grid at the Grid Insertion Point.

Connection Charge

5.9 The Code definition of a 'connection asset' appears to be indifferent as to whether a generating plant is connected to the distribution network or the transmission network. [16] This translates into a consistent basis of charging for connection assets resulting in a **competitively neutral** position. Both Transpower and the EDBs currently charge the *incremental* cost of (1) Any capital connection incurred, and subsequently (2) The Operating capacity costs (excluding and common costs) of any new connection asset. EDB connected Distributed Generation thus *justifiably* avoid Grid transmission costs **and** EDB common costs**.**

5.10 This implied equivalence needs to be validated [17] particularly as it maximises incremental generation to the system, in the shortest time frame, in an economically optimal fashion.

Recommendation 6 – That the EA preserve the *status quo* definition of "connection assets" and that common costs *remain excluded* from the definition.

Recommendation 7 – That any other regulated transmission or network costs allocated must be assessed on the Beneficiaries Based Cost methodology and also be net of the benefits provided to the infrastructure providers. E.g. by using standardised ACOD and ACOT connection code provisions.

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[15] Voltage support may be provided on either the transmission or distribution networks.

[16] The Code defines connection assets as: "for the purposes of sub-parts 2, 6 and 7 of Part 12, has the meaning set out in the transmission pricing methodology".

[17] Refer to the Distributed Generation Pricing Principles Consultation.

5.11 EDBs also appear to have adopted a general market practice of an onerous Connection Asset "Vesting" clause. Current EDB industry practice is for the ownership of connection assets to transfer to the EDB **despite being paid for by the DG.** We see several commercial implications from this "questionable" business practice. Once vested, these assets are recognised on the EDBs asset base and benefit their accounts accordingly – although they are deducted from the Regulated Asset Base when determining Weighted Average Cost of Capital derived revenue.

5.12 This appears to be ***clear potential*** for :

- The exercise of anti-competitive monopolistic behaviour.
- Collusive behaviour by the EDBs – the practice appears to be universal.
- A failure in either the monitoring or enforcement regime by the Regulator.

5.13 The key commercial risk to Distributed Generators is load connection as it incurs common costs not incremental costs. It is thus subject to higher future common charges - despite already vesting the assets to EDB's at lower regulated returns.

Questions 8 : **Are the EA aware of this ? If so why has this practice been allowed**?

Recommendation 8 – **That the EA undertake a survey of this practice focusing on quantifying the opportunities that were lost / delayed by this practice.**

Recommendation 9 – **That the EA requires a reversal of this "Vesting" practice.**

5.14 We believe that BESS *connected directly into a network* or grid is arguably a connection asset. **Without clear title, front of meter BESS are uninvestable except by the immediate owners of the network or grid.**

5.15 This has also acted to impede the better capitalised, higher capability EDBs from supplying BESS as part of network solutions into other lines networks designated geographic networks.

5.16 We support our "in the shortest time frame" contention with the observations that the listed Gentailers (and Manawa Energy) are :

- Towards the upper limit of their funding capability – without raising additional equity capital.
- Capability constrained functionally to *accelerate* the existing development objectives – particularly solar. [18]

[18] At the Wellington consultation on 24 March 2025, the EA publicly acknowledged that they had accepted Gentailer claims that they were already "doing their best".

- Constrained by their shareholder base that is orientated toward dividend yield – and so would risk a further fall in share price if dividends were reduced to fund growth.

5.17 Interestingly, our previous observations about the Gentailer constraints also apply to the 29 EDBs as a class. This suggests that new development capital is more likely to be provided by external investors. This view is illustrated by Genesis Energy's market briefings that their growth aspirations would be funded by a preference towards Special Purpose Vehicles (off balance sheet vehicles).

Recommendation 10 – That the EA standardise the connection terms for Distributed Generation as a class, including that the contract term matches the economic life of the asset.

5.18 Every solar site has an inverter to convert from DC to AC supply thus providing every solar site with the opportunity for distributed storage batteries. The aggregated battery storage opportunity with solar generation therefore has the potential to change the management of both the transmission system and operation of grid generation. The combination of local solar and battery system is now cost effective as a demand manager and market supply price cap, ***but is being penalised by high fixed network charges***.

5.19 From a policy perspective, we rank economic desirability (best to worst) in the following manner.

1. Solar Generation Behind the meter **plus** Battery.
2. Solar Generation Behind the meter.
3. Solar Generation Front-of-meter.
4. Stand-alone battery Behind-the-meter.
5. Stand-alone battery Front-of-meter.

Retrospective Charges Example - Lodestone Energy

5.20 Distributed Generation should also **not** be penalised *retrospectively* by ***future*** regulations. By example, the recent Transpower 2023 recalculation of transmission pricing allocations (TPM), using the beneficiary based cost allocations methodology (BBC), to retrospectively allocate to **Lodestone Energy** transmission costs for their recently built Edgecumbe (32MW) and Waiotahe (43MW) network embedded solar farms.

Question 9 : Was there a similar (Whole-of-System) cost-benefit methodology applied to Lodestone Energy that would have recognised any related local network or transmission benefits"?

By example, this may have included lower transmission and distribution losses, voltage management options using their inverter technology, battery siting options at the solar site location, or avoided future peak demands across the regional network?

Question 10 : How would Lodestone Energy apply ACOD or ACOT to a storage battery investment at their Edgecumbe and Waiotahe sites in the Bay of Plenty, to not incur the latest Transmission Pricing Mechanism / Beneficiaries Based Cost allocations and at the same time provide support services to both EDB and Transpower systems?.

Recommendation 11 – That retrospective charges be prohibited as a regulatory policy.

Recommendation 12 – That any other regulated transmission or network costs allocated to DGs must be assessed on similar benefit based cost methodology and also be net of benefits provided to the infrastructure providers. E.g. by using standardised ACOD and ACOT connection code provisions.

Recommendation 13 – That Transpower's common costs be solely allocated to load customers. (DG not directly connected)

6.0 Non-Network Solutions

6.1 For the purposes of this submission, Non-network Solutions (NNS) are defined as :

a) Batteries for grid and network support,
b) Demand-side response from loads,
c) Distributed Generation ***with*** battery storage.

6.2 Behind the meter, on-site, **non-network solutions** theoretically hold the greatest potential for the Electricity Authority to reduce ***aggregate*** system costs (both opex and capex) and therefore fulfil the stated EA objective of maximising the value of new technology [19].

6.3 As a policy position, investments in **Non-Network Solutions** should be encouraged whenever possible they are both *competitively neutral* and *outcomes focused* in policy approach. Their provision is open to the incumbent network providers, they are competitively neutral. They also benefit from having a greater speed to market of delivery **and** a lower capital intensity. **They thus offer the potential to rapidly address many of the capacity and capital issues constraining investment.**

6.4 NNS need commercial structures and contracts that align with the value share and commercial realities. With few exception, NNS are only being assessed by EDBs as a CAPEX with no value stacking.

6.5 Battery electric storage systems have multiple applications including peak **demand *smoothing*** and Fast & Slow Instantaneous Reserves**.**

6.6 **There thus appears to be *significant potential* for the aggregation of Electric Vehicle (EV) battery storage to provide these market services as close to the load centers as feasible**. EV's are essentially a "sunk cost" asset acquired by consumers as an essential asset. This indicates that EV storage is likely to be the most cost-efficient storage available to the market to provide such services.

Question 11 *:***Does the EA and ComCom have a clear view on this EV storage potential, and how the regulations can be structured to ensure this potential can be realised as** *quickly as possible?*

6.7 The September 2024 Sapere report [20] at pg. 8 noted that "some services, such as instantaneous reserves could be relatively easily opened to suitable Distributed Energy Resources" .

Recommendation 14 – That Non-network Solutions be encouraged as a policy position by the provision of incentives for on-site solutions to reduce or time shift energy demand and carbon emissions.

[19] EA Issues Paper – Updating the Regulatory Settings For Distribution Networks (December 2022).
[20] Sapere - Confluence of factors threatening electricity reliability (September 2024).

Recommendation 15 – **That a policy requiring a non-network solution counterfactual be provided in all ACOD / ACOT cost benefit analyses.**

Recommendation 16 – **That all decisions and reporting on NNS options and all cost-benefit analyses need to be made transparently, and be subject to independent peer review when contested.**

7.0 Requirement for Assurance

"Trust, but verify". **Russian proverb popularised by Ronald Reagan**

7.1 *In my opinion*, the provided Risk Management Options from this Consultation will be perceived as ***flawed*** without independent assurance around standardised Guidelines that enable the consistent calculation of the electricity Retail Margins.

Noting that:

- Prescription *also* benefits the Gentailers as it minimises the establishment friction costs and the comparability between Gentailers immediately.
- ***A desktop gap analysis of the EA Board suggests this obvious fatal flaw may have been avoided with Accounting / Assurance expertise on the EA Board?***

Recommendation 17 – **That guidelines be provided for the calculation of Gentailer Retail Margins be prescribed at the outset..**

Recommendation 18 – **That mandatory independent Assurance be required in the calculation of Gentailer Retail Margins.**

7.2 There is a reasonable degree of subjectivity around the accounting calculation of a Retail Margin for a vertically integrated Gentailer. Stakeholder scepticism about the appropriateness of a conflicted, "self-assessed" retail margin calculation would be both understandable and justified.

Noting that:

- A "self-assessment" reporting regime will provide limited confidence in the comparability of both the absolute and relative Margins between Gentailers.
- It will also *inevitably* lead to restatements and in all likelihood a course correction to higher touch regime.
- Segmental cashflow varies from recognised accounting profit. Reported retail profitability

Recommendation 19 – **That the EA Board add Accounting & Audit expertise to its membership.**

7.3 I support the current policy objective that vertical integration for Gentailers is preferred as it should lead to lower, average long-term energy prices. But structural separation can only be preserved if the current perceptions regarding retail margin disclosures are addressed through independent Assurance.

7.4 The absence of verifiable EA Guidelines from the outset of a revised framework result in avoidable compliance costs were the EA be subsequently required to migrate the reporting requirements from a lower touch model.

7.5 The unverified disclosure framework contrasts with the regulatory disclosure and assurance regime found in the NZ Banking & Insurance sectors [21]. This situation can ***be readily addressed, albeit at the "cost" of a delayed implementation***.

Noting that:

- Assurance around a defined retail margin may allow disclosure simplification and possible a "net" cost or even benefit.
- Definitional consultation may possibly extend the implementation date by an estimated 4 – 6 months.

Recommendation 20 – If a non-Assurance regulatory framework is adopted, an explicit rationale with a cost benefit analysis needs to be provided to stakeholders – as per the policy in financial markets standards setting.

Recommendation 21 – If an Assurance framework is adopted, a review of the suite of disclosures should also be conducted to ascertain if some could be eliminated or simplified – thereby resulting in a "net" cost.

7.6 We would argue that an independently verifiable assurance regime is now **unavoidable** given the historic lack of code clarity on assessing ACOD / ACOT and the ***perception*** that the existing regulatory framework is implicitly being gamed by the EDBs with plausible deniability.

Recommendation 22 – That the code requires urgent clarification on assessing the Avoidable Cost of Distribution Benefits.

[21] The banks are subject to the Audit & Assurance standards as set by the External Reporting board for both their financial reporting obligations **and** the Orders in Council for the separate Banking Prudential Requirements.

8.0. D'Souza Associates

8.1. ***D'Souza Associates*** is a corporate finance consultancy specialising in the provision of advice on:

- √ Mergers & Acquisitions,
- √ Financial Markets Standards Setting & Enforcement.
- √ Valuation, and
- √ Corporate Strategy / Capital Management.

8.2. Since 1985, I have held a variety of roles in the NZ financial markets that has given me the relatively broad experience as a Practitioner, Standards-setter, Regulator, and Financial Industry body governance.

a) **Funds Management** – at AMP Capital Investors as a Senior Equity Analyst and Portfolio Manager. (**1985 – 1993)**

b) **Share Broking / Investment Banking** – at Citigroup New Zealand firstly as their New Zealand Institutional Equities Research Director and then as a Director in Investment Banking. (**1994 – 2002)**

c) **Finance Industry Body** – through my governance role as a board member of the Institute of Financial Professional New Zealand (INFINZ) [22]. **(2013 – 2022)**

d) **NZ Accounting Standards Board (2011– 2016)** – the statutory financial reporting standards-setter for NZ.

a) **NZ Audit & Assurance Standards Board (2016 – 2022)** – the statutory Auditing and Assurance standards-setter for NZ.

b) **NZ RegCo** – the regulatory arm of the NZ Stock Exchange (NZRegCo), for whom I provide expert opinions on investigations into potential breaches of the Continuous Disclosure obligations and disclosure Waiver applications.

c) **NZ Treasury** – policy advice on the regulatory settings for the NZ Super Fund.

[22] The +2,400-member industry body representing *wholesale* capital markets professionals. I was made an INFINZ Fellow in 2023 – one of only 40.

9.0 Appendix

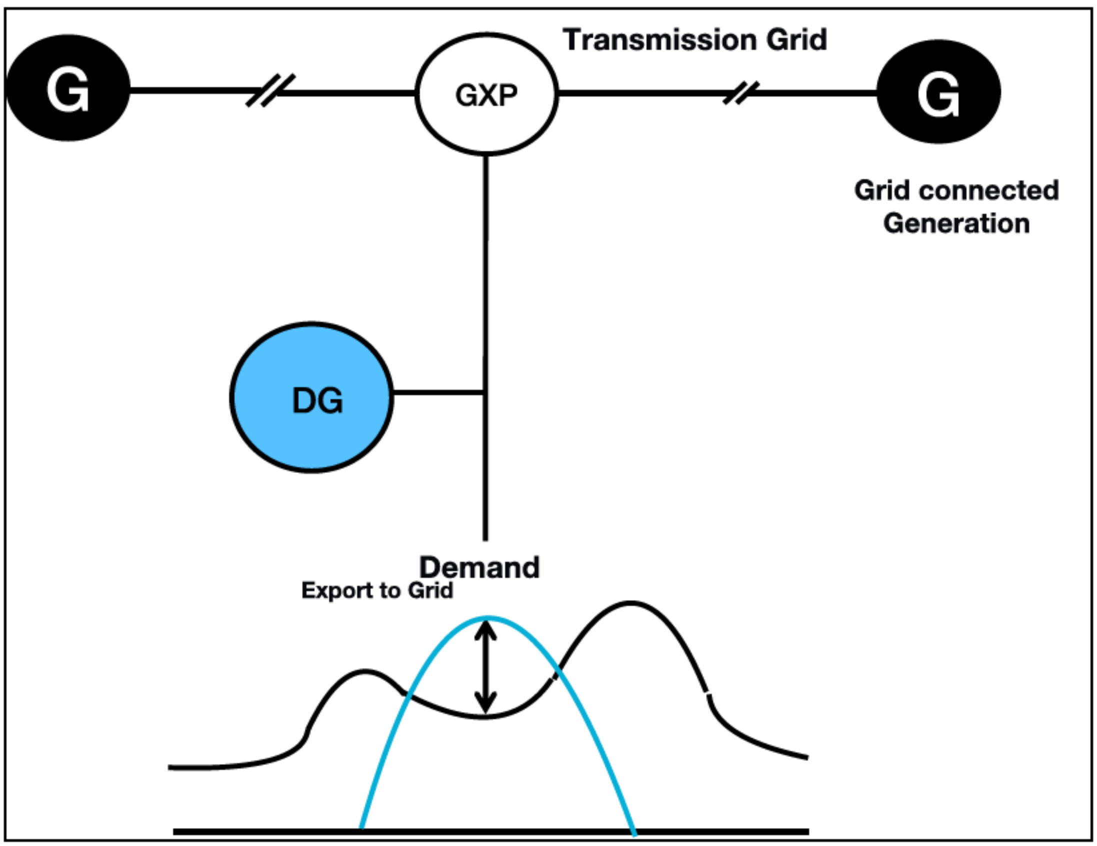
Solar Generation Front of Meter DG Example

9.1 **Figure 8** presents a graphic of a solar "front of meter" Distributed Generator. The Blue curve illustrates the level of generation supply during the day equates to the network demand trough **between** the 7am to 9am and 6pm the 9pm demand peaks (the Black curve). The system "only" benefits from the export of into the Grid during the demand trough and marginally reduces the two intra-day demand peaks.

9.2 It exports DG into the Grid during the demand trough and likely marginally reduces the two intra-day demand peaks, and more in summer than in winter.

9.3 The greater the DG exported into the Grid the lower the demand for alternate, more distant from source, Grid generation and thus the lower the Grid energy losses (the more efficient the system).

Figure 8 : Solar Distributed Generation – connected into a 33kV or 11kV network)

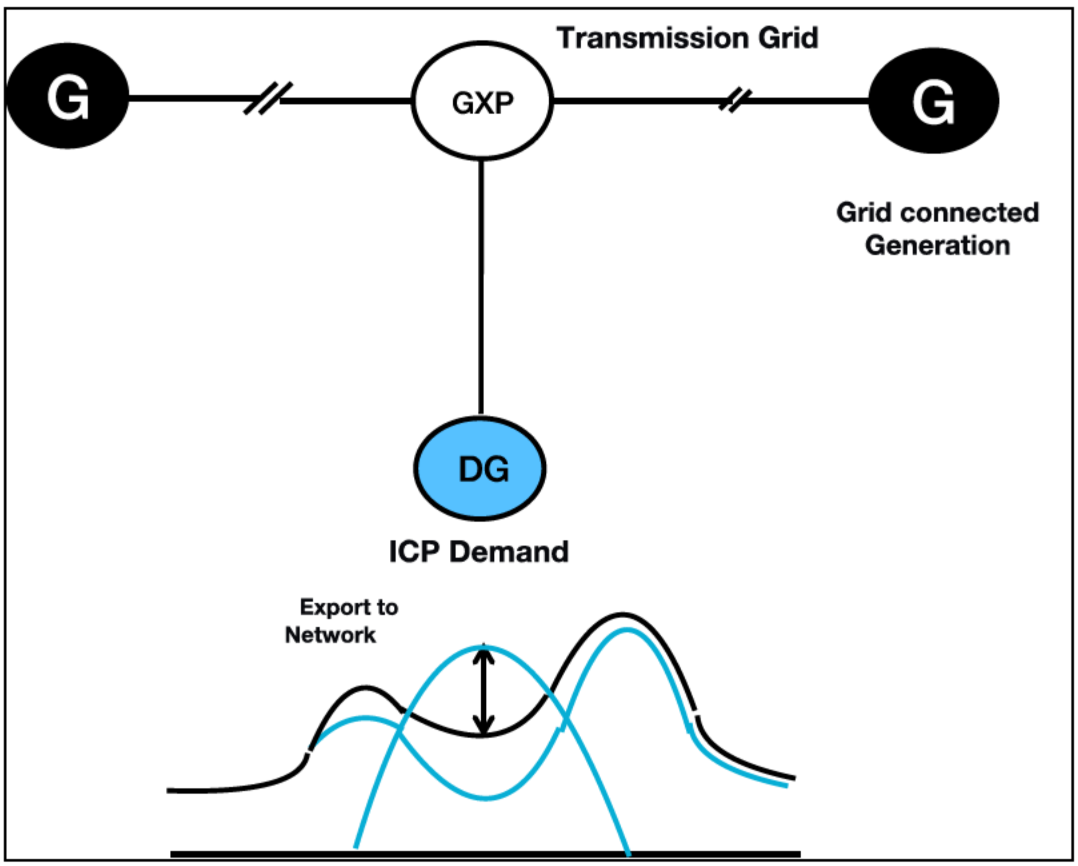


Source : D'Souza Associates

Solar Generation Behind the Meter DG Example

9.4 **Figure 9** presents a graphic example of a solar "behind the meter" Distributed Generator. The graphic illustrates how behind the meter generation reduces the (a) peak, (b) gross demand and (c) Net demand on the system by exporting the surplus generation during the day. The gross demand is reduced by for example charging an EV or other discretionary appliance demand to take most advantage of the excess daytime solar production and reduce the lower value export back to Network and Grid.

Figure 9 : Solar Generation Behind the Meter (no storage)



Source : D'Souza Associates

Solar Generation plus Battery Behind the Meter DG Example

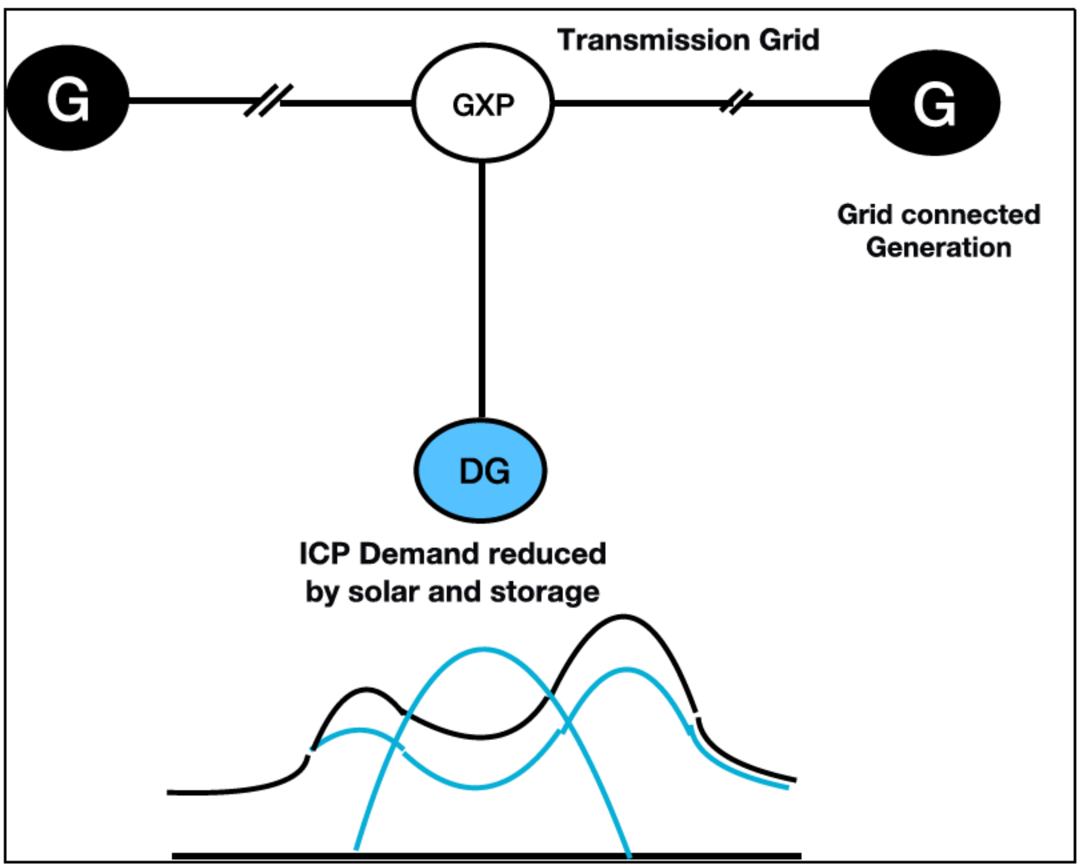
9.5 DG + Storage behind the meter provides the ***most economically efficient electricity delivery system. It does this*** by reducing demands on Grid Generation, on Transmission and on Network systems, thereby also reducing line losses.

9.6 **Figure 10** presents a graphic example of a solar Distributed Generator plus BESS "behind the meter". The Black line illustrates the pre-generation demand peaks between the 7am to 9am and the 6pm the 9pm demand peaks.

9.7 Storage behind the meter avoids solar export into market and moves solar production into peak demand periods to avoid higher market spot energy costs

9.8 DG Storage reduces both daily demand peaks by shifting daytime solar into evening peaks and acquiring demand over-night during low demand period and serving the morning peak market demand peaks.

Figure 10 : Solar Generation plus Battery - Behind the Meter



Source : D'Souza Associates