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System Operator
Transpower
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Tēnā koe,

TSO-DSO coordination: operational requirements

Powerco welcomes the System Operator (**SO**)'s discussion paper on operational requirements for coordination between transmission and distribution system operators (**TSO** and **DSO**). We support the five requirements as a starting framework and the principles for developing operational requirements.

Powerco's vision is to be Aotearoa New Zealand's most customer-focused infrastructure owner and operator. As part of this, Powerco has a core strategic objective of operating as a DSO by 2030. Enabling this transformation requires a sound operating relationship with the SO, especially as our respective capabilities mature.

We encourage the development of operational requirements that are proportionate, ensure clear accountability and acknowledge that distributors will have different approaches to interacting with customer energy resources and market co-ordinators. Our key messages are:

Information should come from the party best placed to provide it	• For most items in Requirements 2 and 3 that party is the asset owner, the retailer or aggregator that controls the load, or the network owner. • Where a distributor holds copies of this information, it is not best party placed to provide it • For clarity in implementation, it is important that only one party is responsible.
The System Operator and EDBs have different tools for obtaining information.	• Part 8 of the Code already places information duties on the owners of distributed energy resources • Asset owner performance obligations (**AOPO**s) for parties connected to the transmission network are enforced by Code and Grid Owner connection contracts • For small resources connected to a distribution network, neither the SO nor the electricity distribution business (**EDB**) has enforcement tools of the same kind.
Start with existing information exchanges	• We welcome the SO's suggestion of a working group to progress implementation • Prioritise existing information exchanges, starting with planned outages and the data passed under the inter-control centre communications protocol.

We provide feedback on these themes in the attachment including comment on each of the five proposed requirements in Section 5.

We would be keen to support implementation through the SO's proposed working group. In the meantime, if you have any questions or would like to talk further on the points we have raised, please contact me at Emma.Wilson@powerco.co.nz.

Nāku noa, nā,



Emma Wilson
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1. Introduction

Powerco's strategic objective is to become a fully functioning DSO by 2030. Powerco's DSO model will be designed to send signals of network congestion and power quality to drive market-based responses, rather than controlling customer devices directly. The development of any operational arrangements should accommodate trader-led flexibility approaches and market-based orchestration and should not be contingent on a DSO exercising direct control over all distribution-connected resources.

With the increased complexity of power-flows and diversity of generation and storage on both transmission and distribution networks, it is important for any co-ordination framework to reflect the increased information needs of both the TSO and EDBs. New operational requirements should also reflect the clear difference in roles between the SO and EDBs.

2. Information should come from the party best placed to provide it

We support the principles for developing operational requirements, in particular the second principle that information should flow in both directions and come from the party best placed to provide it. Applying this to requirements 2 and 3 clarifies which party is best placed and incentivised to provide and maintain information. The tables below outline our view on which party should be responsible for information items under requirements 2 and 3.

We note that in many cases EDBs hold copies or estimates of information only. This may be a convenient source for the SO, but the EDB is not best placed where it can't provide information which is authoritative and accurate.

Requirement 2: Minimum static information

Information item	Best placed to provide	Rationale
Installed embedded generation and batteries	Asset owner EDB in aggregate	Asset owners are the primary source of data about equipment and its settings. EDBs hold secondary data on connection applications and aggregate demand at each grid exit point.
Large loads and data centres	Asset owner EDB and Grid Owner for contracted capacity	Asset owners are the primary source of data about load and how it operates. Network owners hold secondary data on contracted capacity.
Controllable demand and flexibility	Retailer or aggregator EDB for its own load control	The party with delegated authority for control is the primary source of information on controllable demand and flexibility. EDBs only know about load and flexibility that they control or contract directly.

Information item	Best placed to provide	Rationale
Network equivalents, impedances and topology	EDB and Grid Owner	Each network owner holds and maintains its own model. The System Operator combines secondary data from these models.
Technical performance and protection	Asset owner for settings and performance. EDB and Grid Owner for network protection	Asset owners hold source data on settings. Likewise network owners are the source of network protection information.

Requirement 3: Minimum dynamic information

Information item	Best placed to provide	Rationale
Aggregate MW and MVAr, actual and forecast	Asset owner for large plant Network owners for aggregate forecasts	Asset owners are the primary source of data about load and how it operates. Network owners use secondary and historic aggregate data to forecast load.
Available and activated controllable demand	Retailer or aggregator EDB for its own load control	The party with delegated authority for control is the primary source of information on controllable demand and flexibility. EDBs only know about load and flexibility that they control or contract directly.
Material availability and state of distributed energy resources	Asset owner for settings and performance. EDB and Grid Owner for network constraints	Asset owners hold source data on settings. Network owners are the source of network constraint information.
Material distribution faults, outages and loss of control	EDB	EDBs are the primary source of information on distribution faults, outages and loss of control.

In none of these cases is the SO or the Electricity Authority (Authority) a primary information source.

3. The SO and EDBs have different tools for obtaining information

Part 8 of the Code applies to larger distributed energy resources in several ways, but the SO and EDBs have different tools to obtain and enforce technical compliance and information provision.

Part 8 requires large asset owners to comply with the technical codes and the SO's connected asset commissioning, testing and information standard and to provide information and communication facilities that meet that standard. Generating stations of less than 10 MW are exempt from the frequency and fault ride-through obligations and to the emergency code but are not exempt from information obligations. Separately, generators must notify the SO

when connecting units of >1 MW to a local network, and EDBs must use reasonable endeavours to make sure that it does.

When a party connects to the transmission network, they, the SO and the Grid Owner are all subject to Code provisions. The SO has a further enforcement tool through the Grid Owner's connection contracts as a result of the Part 12 requirement for each connected party to have a transmission agreement with the Grid Owner. Default terms oblige the connected party for injection >1MW to provide capability information to the Grid Owner even when connected behind a GXP.[1]

An EDB has a different set of tools. It connects distributed generation under Part 6 of the Code and its own network connection standards. Powerco's standards let us require design and protection information when a generator applies, ask for meter data on request, require SCADA visibility above 500 kW, and curtail or disconnect generation for network safety or to meet obligations placed on us by the SO through the Code.[2] Our application form also asks for any other information that the SO requires.

Where a party connects to a distribution network, some resources are not directly subject to the Code in the same way that they would be if transmission connected. Part 8 does not place information or compliance obligations on units below 1 MW, so reporting on a fleet of smaller units would only apply if the Authority were to approve a group requirement to market participants. The EDB is solely subject to the Code as a supplier of line function services. There is no "DSO" Code participant on responsible for local network market operation and real-time reliability coordination by analogy with the TSO.

Controllable load is dealt with Technical Code B, which applies to EDBs but excludes embedded generators and does not apply to retailers (or aggregators). Powerco's default distributor agreement applies to the EDB and the retailer and covers load control and the protocol for system emergency events, but it does not apply to customers or non-retailing aggregators directly.

The Authority's recent consultation paper on sharing common quality information did not propose a Code change for information sharing between the SO and EDBs. The Authority has informally confirmed that its final decision will not change but that, in response to Powerco's submission that information sharing between EDBs and the SO will be increasingly important as the power system evolves, the Authority remains open to revisiting the question in future. The Authority also noted that submitters ranked visibility of behind-the-meter resources and the role of aggregators as higher priorities.[3]

Given that the SO's proposed working group would include participation by the Authority, it would be a practical forum to assess the costs and benefits for strengthening or modifying Code provisions or contracts that require parties to supply information and enforce technical obligations.

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[1] Electricity Authority, *Proposal for Transpower to share common quality information between System Operator and network owner functions*, consultation paper, paragraphs 3.6 to 3.8 (Part 12 of the Code and Schedule 12.6, the default transmission agreement terms).
[2] Powerco, Distributed Generation (DG) Policy, 173S003; Distributed Generation Over 10kW Connection Standard, 393S012; Distributed Generation Up to 10kW Connection Standard, 393S089.
[3] Electricity Authority, *Proposal for Transpower to share common quality information between System Operator and network owner functions*, consultation paper, paragraphs 2.18 and 2.19. Powerco's submission of 11 August 2026..

4. Start with existing information exchanges

The discussion document asks for a small number of priority information exchanges. From Powerco's perspective, processes around planned Grid outages and ICCP data sharing should be prioritised.

Example 1: Planned Grid outages

Information	Outage dates, the grid exit points and assets affected, the load the distributor can transfer and its switching constraints, and the embedded generation affected.
Source	Grid Owner: planned outages EDB: local network constraints and outage plans Embedded generators: availability SO: assessment of the effect on security.
Code provisions	Technical Code D of Schedule 8.3 requires each EDB to notify outages of assets connected directly to the grid, and of indirectly connected assets that may affect the SO's compliance. The transmission agreement between the grid owner and the distributor also sets outage terms.

As the amount of Large DER connected to the distribution network increases, coordinating planned outages will become more complex. For example, during an outage we may transfer part of a feeder containing DER to another GXP. That DER may not be approved to operate under the alternate GXP, even where its generation is fully self-consumed within the distribution network.

Example 2: Inter control centre communications protocol exchange of controllable load and grid exit point measurements

Information	Available controllable load at each grid exit point, and voltage and current at the grid exit point, which pass between control centres over the inter-control centre communications protocol (**ICCP**).
Source	EDB: forecasted available controllable load Grid Owner: meter data at the grid exit point.
Code provisions	Clause 5A of Technical Code B requires each EDB, on request, to report its available controllable load through difference bids at a single price of $20,000 per MWh at each conforming grid exit point. The distributor must revise the bids as its estimate changes and supply data within five business days of a request to reduce load. The Code requires communication facilities that meet the information standard, which now sets the minimum requirements for operational communications (clause 8.74(e)). New CACTIS obligations place additional Code obligations on EDBs by reference.

A further example is the curtailment of embedded generation, where the SO and an EDB can each constrain the same plant. For example, we have agreed protocols with the SO for generation at Pāmu Rāki and Whitianga.

The proposed working group could begin with these examples, map the information flows and the authority behind each, identify the gaps, pilot exchanges where authority already exists, and recommend targeted changes where it does not.

5. Responses to the five operational requirements

Our view on each proposed requirement is outlined in the table below.

Transpower requirement	Powerco response
Requirement 1: Clear operational accountabilities	Accountability should flow to those with access to information and incentives to maintain it. The System Operator, EDBs, asset owners, and retailers or aggregators have different tools today, as set out above, so the framework could separate information exchange, coordination and direct control, and treat control as an exception for defined emergencies.
Requirement 2: Minimum static information	The table in Section 1 above sets which sources are best placed to provide information. A minimum dataset could be tied to the decisions it supports, with aggregate data at each grid exit point as the default, and a distributor could not certify third-party data that it has no means to verify.
Requirement 3: Minimum dynamic information	The table in Section 1 above sets which sources are best placed to provide information. Dynamic information should be proportionate to the SO's needs for operational decision making. Secondary forecasts may not be reliable enough for the SO's purposes. For example, EDBs cannot reliably predict all market-driven actions of customer owned resources, and EDB forecasts will only ever be estimates. Visibility could also run both ways, including SO actions that affect resources connected to distribution networks.
Requirement 4: Interoperable information exchange	Exchange should be technology-neutral and could use existing channels such as ICCP where they fit. Information should be supplied once and made available to authorised parties, with sharing rights and access controls agreed before any exchange starts. Interoperability is a key principle while protecting commercial IP or customer confidentiality.
Requirement 5: Predictable technical performance	Predictable performance should relate to capability within an agreed operating range, which may differ from commercial availability. Obligations should sit with the party that can specify, maintain or control the performance. Requirements should remain technology-neutral and recognise distribution network operating constraints.