TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Attachment 9: Indicative Pricing Impacts

August 2025

Purpose

Under the transmission pricing methodology (**TPM**),[1] the covered costs[2] of post-2019 investments in interconnection assets and interconnection transmission alternatives (post-2019 benefit-based investments or **BBIs**) are recovered from customers identified as beneficiaries. These allocations are based on each customer's expected positive net private benefit (**NPB**) from those investments. The charges through which the covered costs are recovered are called benefit-based charges or **BBCs**. The TPM contains the methods for calculating BBCs.

This attachment presents information to the Commerce Commission (**Commission**) and other stakeholders about the indicative increase in transmission charges (specifically indicative BBCs) due to the Upper South Island (**USI**) Upgrade Stage 1 Project, which will result in a high-value[3] post-2019 BBI (referred to as the **USI Upgrade Stage 1 BBI**). This attachment includes indicative starting allocations and indicative covered costs for the BBI, from which we have calculated indicative BBCs.

Following the Commission's final decision and Transpower's final investment decision on this MCP, we will undertake a formal consultation on the proposed starting allocations for the USI Upgrade Stage 1 BBI, as required by the TPM.

We have used the methodologies outlined in the TPM and BBC Assumptions Book[4] to produce the indicative starting allocations in this attachment. However, our calculations have not been at the level of detail we will apply when we calculate proposed starting allocations for the USI Upgrade Stage 1 BBI for consultation under the TPM (as noted above, this will be after the Commission's final decision and Transpower's final investment decision on this MCP). Nevertheless, we consider the indicative starting allocations presented in this attachment provide a reasonable indication of the distribution of NPB from the preferred option.

We emphasise that the indicative starting allocations, covered costs and BBCs in this attachment are indicative only, and not the proposed or final starting allocations, covered costs or BBCs for the BBI. There may be changes to the inputs for calculating the BBCs between now and when the starting BBCs are finalised, including BBC adjustment events under the TPM. Transpower cannot, and does not, accept any liability for the accuracy or completeness of the information provided, nor for any consequences arising from any party's reliance on it. We strongly recommend that stakeholders review the TPM and Assumptions Book themselves and seek independent expert advice before relying on any information in this attachment.

Unless otherwise stated, all clause references in this attachment refer to clauses within the TPM.

1 The TPM is in Schedule 12.4 of Part 12 of the Electricity Industry participation Code (Part 12 - Transport).

2 The cost recovered through the benefit-based charges for a benefit-based investment is referred to in the TPM as the 'covered cost'.

3 A high-value BBI is a BBI that is expected to involve capital expenditure and/or transmission alternative operating expenditure of more than the base capex threshold under the Capex IM. The base capex threshold is $20m for this project because it was notified to the Commission prior to 1 April 2025.

4 The Assumptions Book contains detail about how the TPM is applied to calculate BBCs and the inputs to those calculations.

Contents

1 Background

1.1 Investments comprising the USI Upgrade Stage 1 Project

The investments that comprise the USI Upgrade Stage 1 Project are the following:

a. New switching stations at Orari and Rangitata ($103m)

b. Tactical thermal upgrades of the Norwood–Rangitata and Orari–Rangitata lines to enhance the transfer capacity to the USI ($50m)

c. New 150 MVar shunt capacitor at Orari ($11m)

d. Automatic over-voltage capacitor switching scheme ($1m).

Additional detail about this investment, and the wider proposed investment it is the first stage of, can be found in Attachment 3.

The USI Upgrade Stage 1 Project, which has an expected cost of $167 million, will result in a high-value post-2019 BBI because it is an interconnection investment, will be commissioned after 23 July 2019,[5] and is forecast to cost more than $20m (being the applicable base capex threshold under the *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2 (**Capex IM**)). The USI Upgrade Stage 1 Project is expected to be completed, and the investments under it commissioned, by 31 December 2030.

The Assumptions Book, at paragraph 259, describes when it may be necessary to break a project into more than one BBI. We have assessed the individual investments that comprise the USI Upgrade Stage 1 Project against the criteria in paragraph 259 of the Assumptions Book and determined they should be treated as a single BBI because the investments are occurring in the same region and address a single need, namely insufficient transmission capacity in the Upper South Island region to meet the forecast load growth. In this attachment we call this BBI the USI Upgrade Stage 1 BBI.

As the USI Upgrade Stage 1 BBI is a high-value post-2019 BBI, Transpower must use a standard method under the TPM to determine the BBI's beneficiary customers and calculate their starting allocations.

We have used the price-quantity method[6] for the USI Upgrade Stage 1 BBI because it is not a resiliency BBI – its primary investment need is to alleviate, or prevent, transmission constraints that would affect quantities and prices in the wholesale electricity market, not to mitigate a risk of cascade failure or a high impact, low probability event.

Within the price-quantity method there are four types of regional NPB that may be calculated – market regional NPB, ancillary service regional NPB, reliability regional NPB and other regional NPB.

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[5] 23 July 2019 is the date the TPM uses to distinguish between pre- and post-2019.

[6] Price-quantity method is detailed in clauses 44 to 55 of the TPM.

For the USI Upgrade Stage 1 BBI, we have calculated market regional NPB only (regional NPB relating to changes in quantities and prices in the wholesale electricity market). This is because we expect most of the benefits of the BBI to be derived from market benefit.

Within the price-quantity method there are two options for calculating market regional NPB arising from changes in the wholesale market for electricity. The default option is to calculate market regional NPB based on quantities during periods of benefit (clause 51). The alternative option uses both quantities and prices to calculate market regional NPB (clause 52).

For the purpose of indicative starting allocations and BBCs, we have used the quantity and price-based option (clause 52) because most of the positive market regional NPB for the USI Upgrade Stage 1 BBI's regional customer groups derives from customers avoiding having to pay their estimated cost of self-supply for electricity during peak demand periods.

1.2 Interaction with the Capex IM

The combined investment value of the USI Upgrade Stage 1 Project is currently estimated at $167 million, and its constituent parts are enhancement investments. This means the USI Upgrade Stage 1 Project is major capex under the Capex IM, for which Transpower must submit a major capex proposal (**MCP**) to the Commission for approval to recover the costs from Transpower's customers.

Under clause 7.5.1(1) of the Capex IM, an MCP must include information about the expected increase in transmission charges due to the proposed expenditure. We have included this and explained our methodology in section 4.

This MCP also includes the market scenarios and other modelling assumptions and parameters we use to apply the Capex IM investment test (**Investment Test**). Clause 43(5) of the TPM generally requires consistency in approach with the Investment Test when we calculate starting allocations for a high-value post-2019 BBI. We may depart from the Investment Test approach if we determine that approach would not produce allocations that are broadly proportionate to NPB from the BBI. Refer to section 3.1 for more details.

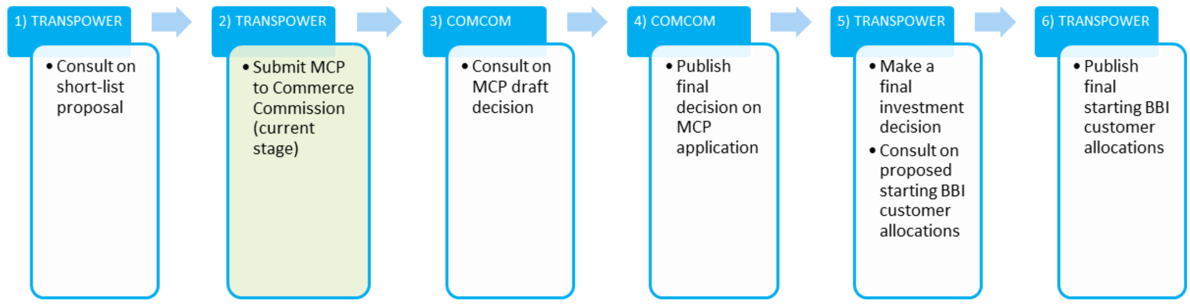
1.3 What happens next?

Under clause 15 of the TPM, Transpower must consult on the proposed starting allocations for each high-value post-2019 BBI. We will therefore consult on the proposed starting allocations for the USI Upgrade Stage 1 BBI before finalising its BBCs.

Assuming the Commission approves the USI Upgrade Stage 1 investment, Transpower will make its final investment decision. If we decide to proceed, we will consult on the proposed starting allocations for the USI Upgrade Stage 1 BBI under the TPM. After considering submissions in response to that consultation, we will finalise the starting allocations and publish them.

These planned stages are illustrated in Figure 1 below.

Figure 1: Planned stages up to publishing starting allocations



2 Indicative covered costs

This section summarises the assumptions used in calculating the indicative covered costs for the USI Upgrade Stage 1 BBI and provides the results of those calculations.

2.1 TPM requirements for calculating covered cost

The cost recovered through the BBCs for a BBI is referred to in the TPM as the BBI's 'covered cost'.[7]

Under the TPM, a BBI's covered cost is calculated annually based on the values of certain capex and opex inputs for the relevant pricing year. A BBI's covered cost is made up of:

- costs that are directly attributable to the BBI or have a verifiable causal relationship with it. This captures capex costs (depreciation and a return on investment using our regulated WACC) and some types of opex; and
- a portion of our "overhead" opex, which does not have a direct or causal relationship with the BBI but is reasonably attributable to it. This type of opex is attributed to all BBIs in proportion to their depreciation (depreciation multiplied by an attributed opex ratio).

2.2 Indicative covered costs

We have used the same cost estimates as in Attachment 5 to calculate the indicative covered costs for the USI Upgrade Stage 1 BBI.

The annual covered cost of a BBI is confirmed as part of calculating transmission charges for each pricing year after the BBI is commissioned. Our calculation of the USI Upgrade Stage 1 BBI's indicative covered cost relies on a number of estimates including final asset composition and asset values, which we will not know until after the BBI is fully commissioned.

[7] For more information see also Transpower's TPM Information Sheet - BBC Covered Cost v2.pdf.

Figure 2: USI Upgrade Stage 1 BBI indicative covered costs

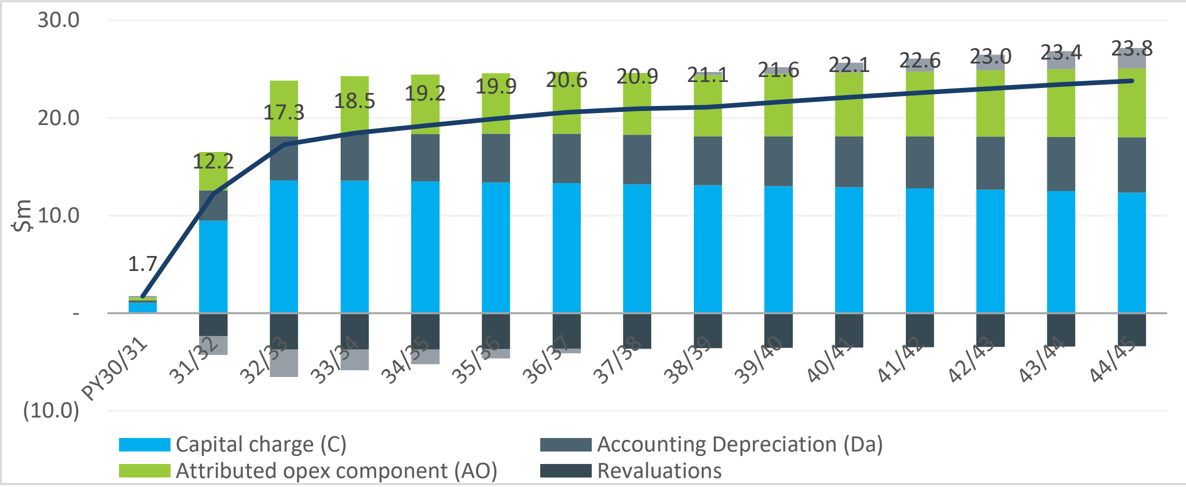


Table 1: USI Upgrade Stage 1 BBI indicative covered costs

Pricing year, PY (starting 1 April)	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39	39/40	40/41	41/42	42/43	43/44	44/45
Accounting Depreciation (Da)	0.2	3.1	4.5	4.8	4.9	5.0	5.1	5.1	5.0	5.1	5.2	5.3	5.4	5.5	5.6
Capital charge (C)	1.1	9.5	13.6	13.6	13.5	13.4	13.3	13.2	13.1	13.0	12.9	12.8	12.7	12.5	12.4
Revaluations	-	(2.3)	(3.7)	(3.7)	(3.7)	(3.7)	(3.7)	(3.6)	(3.6)	(3.6)	(3.5)	(3.5)	(3.5)	(3.4)	(3.4)
Attributed opex component (AO)	0.3	3.9	5.7	6.0	6.1	6.2	6.3	6.3	6.3	6.4	6.5	6.7	6.8	6.9	7.1
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	0.1	(1.9)	(2.8)	(2.1)	(1.5)	(1.0)	(0.5)	(0.1)	0.3	0.7	1.0	1.3	1.6	1.9	2.1
Total forecast covered cost	1.7	12.2	17.3	18.5	19.2	19.9	20.6	20.9	21.1	21.6	22.1	22.6	23.0	23.4	23.8

Some key assumptions and inputs we have applied to calculate the BBI's indicative covered cost are as follows:

- The accounting and tax depreciation rates used are the weighted average rates applicable to the assets that make up the MCP.
- Vanilla WACC (7.10%), cost of debt (5.74%) and leverage (41%) approved for Transpower's current regulatory control period (**RCP**), being RCP4, are used in the calculation for all later RCPs.
- The attributable opex ratio for RCP4 is used in the calculation for all later RCPs.

Note, BBCs for the USI Upgrade Stage 1 BBI will continue for pricing years after pricing year 2044/45.

3 Indicative starting allocations

This section summarises our application of the price-quantity method to the USI Upgrade Stage 1 BBI and presents indicative starting allocations.

3.1 Market scenarios and other key modelling assumptions

These indicative starting allocations primarily use the modelling assumptions and inputs from the Investment Test, which are generally consistent with chapter 2 of our Assumptions Book.

The assumptions used are the same as those applied in the application of the Investment Test, except those upgrades associated with stage 2 of the USI Upgrade Project have not been modelled, because these will be the subject of a future MCP, if needed.

The counterfactual and factual scenarios are as follows:

- The counterfactual assumes the existing grid without any of the investments comprised in the USI Upgrade Stage 1 Project implemented.
- The factual assumes all of the investments comprised in the USI Upgrade Stage 1 Project are completed.

Orion noted during our shortlist consultation that its cost allocation may be exacerbated by the pessimistic generation growth scenarios alongside conservatively high load growth projections in the USI. We have not updated our load and generation assumptions for our indicative starting allocations but may do so when we consult on proposed starting allocations for the USI Upgrade Stage 1 BBI under the TPM.

3.2 Modelled regions and market regional NPB

3.2.1 Modelled regions

Following the process in section 3.3.6.9 of the Assumptions Book, we define the following modelled regions for our indicative starting allocations:

- Upper South Island (USI)
- Lower South Island (LSI)
- North Island (NI)
- Studholme (STU) [8]

Modelled regions are identified by grouping GXP/GIPs that experience similar changes in price or quantity due to the alleviation of system constraints.

3.2.2 Market regional NPB

We have calculated market regional NPB based on the modelled change in consumer and producer benefit in the wholesale market for electricity.

We have not included the modelled change in loss and constraint excess received by demand customers as required under clauses 52(3) and 52(4) of the TPM. We will consider including this

8 Studholme is in its own region because it is electrically in the USI for summer and in the LSI for winter. This is due to the Studholme 110kV split.

when we consult on the proposed starting allocations for the USI Upgrade Stage 1 BBI under the TPM.

The USI Upgrade Stage 1 Project will increase grid capacity to USI GXPs, therefore considerably reducing unserved energy in the USI.

The following table shows the indicative allocations of regional NPB to regional customer groups for the USI Upgrade Stage 1 BBI.

Table 2: Indicative allocations of positive regional NPB to regional customer groups

Indicative regional customer group	Indicative regional NPB share
USI_Demand	97.84%
NI_Supply	1.62%
STU_Demand	0.50%
LSI_Supply	0.03%
NI_Demand	0.02%

3.2.3 Indicative starting allocations

As required under the TPM, we calculated each customer's indicative starting allocation for the USI Upgrade Stage 1 BBI as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the indicative starting allocations in Table 3 below (to two decimal places).

Since our consultation, we have determined that the USI BBI should be treated as a peak BBI under clause 65(1) of the TPM. This is because its need is primarily attributable to meeting peak demand, which was addressed in our consultation:

- section 1.1.2 of Attachment 1, specifically "... growing load will necessitate additional investment in both transmission capacity to alleviate thermal constraints and in voltage support to ensure voltage stability remains stable after a fault".
- section 1.1 of Attachment 5, specifically "... most of the positive market regional NPB for the BBI's regional customer groups derives from customers avoiding having to pay their estimated cost of self-supply for electricity during peak demand periods".

To calculate individual NPBs for the purpose of indicative starting allocations we used the intra-regional allocators for each customer based on their mean historical coincident peak offtake (for customers in demand groups) or their mean annual injection (for customers in supply groups). This was done based on their offtake/injection from 1 September 2019 to 31 August 2024.

This calculation will be updated for more recent years' offtake & injection after there is a final investment decision date for the proposed investment and prior to consulting on the proposed starting allocations for the USI Upgrade Stage 1 BBI under the TPM. This will have some impact on the starting allocations, particularly for customers in demand groups as the peak periods will likely change.

Table 3: Indicative starting allocations

Customer Code	Customer Name	Indicative starting allocation (%)
ORON	Orion New Zealand Ltd	57.73%

TASM	Network Tasman Ltd	9.67%
MPOW	Mainpower New Zealand Ltd	9.61%
ALPE	Alpine Energy Ltd	9.01%
MARL	Marlborough Lines Ltd	5.88%
EASH	EA Networks	3.12%
WPOW	Westpower Ltd	1.96%
NELS	Nelson Electricity Ltd	0.87%
BUEL	Buller Electricity Ltd	0.49%
MERI	Meridian Energy Ltd	0.32%
MELW	MEL (West Wind) Ltd	0.30%
MSVP	Mercury SPV Ltd	0.26%
TARW	Tararua Wind Power	0.25%
WAV1	Waverly Wind Farm Ltd	0.20%
MELT	MEL (Te Apiti) Ltd	0.16%
UNET	Wellington Electricity Lines Ltd	0.06%
WELE	WEL Networks Ltd	0.03%
POWN	PowerNet Ltd	0.03%
GENE	Genesis Energy Ltd	0.03%
CTCT	Contact Energy Ltd	0.01%
PANP	Pan Pac Forest Product Ltd	0.01%
WNST	Winstone Pulp International	0.01%
TBOP	Nova Energy Ltd	0.00%
KUPE	Beach Energy Resources NZ (Holdings) Ltd	0.00%
TRNZ	KiwiRail Holdings Ltd	0.00%
POCO	Powerco Ltd	0.00%
METH	Methanex New Zealand Ltd	0.00%
OMVP	OMV NZ Production Ltd	0.00%
SHPK[9]	Southpark Utilities Ltd	0.00%

9 Customers with 0.00% allocation have a small positive allocation but not shown at 2 decimal places.

4 Indicative increase in transmission charges

We have calculated the total indicative increase in transmission charges (specifically BBCs) for each affected GXP/GIP by multiplying the indicative covered cost of the USI Upgrade Stage 1 BBI by the indicative starting allocations from section 3.2.3 above. We have chosen to use the indicative covered cost for pricing year 44/45, as this is when the indicative covered cost peaks.

We have calculated indicative charges on a $/kWh basis for each affected GXP/GIP (clause 7.5.1(c)(ii) of the Capex IM). We have not calculated indicative charges on a $/kW basis (clause 7.5.1(1)(c)(i) of the Capex IM) because doing so would not provide meaningful information – the new TPM does not base transmission charges on demand supplied by the grid.[10] The Commission has confirmed it is comfortable with Transpower not providing this specific information.

Note that Tables 4 and 5 show the indicative increase in BBCs associated with the USI Upgrade Stage 1 BBI, but not the decrease in residual charges that will result from commissioning the BBI. This decrease will happen because the BBI's covered cost will include an attribution of some of Transpower's operating costs (in proportion to the BBI's depreciation), which will shift revenue from residual charges to the BBCs. The decrease in residual charges will be shared across all Transpower's load customers, not just those in the modelled regions.

Table 4: Indicative increases in transmission charges – demand groups

Customer	GXP/GIP	Region	Indicative increase in annual transmission charges in 44/45 ($k)	Indicative increase in transmission charges per kWh of energy supplied in 44/45(c/kWh)
Alpine Energy Ltd	STU	STU	118.21	0.18
Alpine Energy Ltd	TIM	USI	1,317.56	0.36
Alpine Energy Ltd	TKA	USI	82.21	0.41
Alpine Energy Ltd	TMK	USI	627.18	0.22
Buller Electricity Ltd	ORO	USI	115.70	0.32
EA Networks	ASB	USI	743.32	0.16

Beach Energy Resources NZ (Holdings) Ltd	HWA	NI	0.58	0.00
Marlborough Lines Ltd	BLN	USI	1,400.01	0.35
Methanex New Zealand Ltd	MNI	NI	0.30	0.00
Mainpower New Zealand Ltd	ASY	USI	269.66	0.30
Mainpower New Zealand Ltd	CUL	USI	273.21	0.27
Mainpower New Zealand Ltd	KAI	USI	595.69	0.42
Mainpower New Zealand Ltd	SBK	USI	960.14	0.39
Mainpower New Zealand Ltd	WPR	USI	189.53	0.33
Nelson Electricity Ltd	STK	USI	206.33	0.42
OMV NZ Production Ltd	MNI	NI	0.26	0.00
Orion New Zealand Ltd	APS	USI	3.87	0.37
Orion New Zealand Ltd	BRY	USI	2,876.78	0.42
Orion New Zealand Ltd	CLH	USI	9.28	0.52
Orion New Zealand Ltd	COL	USI	4.52	0.39
Orion New Zealand Ltd	HOR	USI	254.86	0.20
Orion New Zealand Ltd	ISL	USI	10,288.92	0.43

Orion New Zealand Ltd	KBY	USI	126.20	0.16
Orion New Zealand Ltd	NWD	USI	177.55	0.14
Pan Pac Forest Product Ltd	WHI	NI	1.45	0.00
Southpark Utilities Ltd	PEN	NI	0.00	0.00
Network Tasman Ltd	KIK	USI	45.67	0.32
Network Tasman Ltd	STK	USI	2,255.16	0.40
KiwiRail Holdings Ltd	BPE	NI	0.00	0.00
KiwiRail Holdings Ltd	HAM	NI	0.01	0.00
KiwiRail Holdings Ltd	PEN	NI	0.27	0.00
KiwiRail Holdings Ltd	SWN	NI	0.23	0.00
KiwiRail Holdings Ltd	TMN	NI	0.02	0.00
KiwiRail Holdings Ltd	TNG	NI	0.01	0.00
Winstone Pulp International	TNG	NI	1.43	0.00
Westpower Ltd	DOB	USI	81.78	0.64
Westpower Ltd	GYM	USI	219.50	0.39
Westpower Ltd	HKK	USI	95.49	0.27
Westpower Ltd	OTI	USI	2.89	0.22

Westpower Ltd	RFN	USI	67.57	0.32

Table 5: Indicative increases in transmission charges – supply groups

Customer	GXP/GIP	Region	Charge for regional supply group in 44/45 ($k)	Indicative charge per kWh of generation in 44/45 (c/kWh)
Contact Energy Ltd	SFD	NI	2.45	0.00
Genesis Energy Ltd	HLY	NI	6.68	0.00
MEL (Te Apiti) Ltd	WDV	NI	38.00	0.01
MEL (West Wind) Ltd	WWD	NI	70.69	0.01
Meridian Energy Ltd	BRB	NI	1.01	0.00
Meridian Energy Ltd	HRP	NI	75.26	0.01
Mercury SPV Ltd	LTN	NI	61.45	0.01
Powerco Ltd	BPE	NI	0.00	0.01
Powerco Ltd	LTN	NI	0.37	0.01
PowerNet Ltd	GOR	LSI	6.82	0.02
Tararua Wind Power	TWC	NI	59.09	0.01
Nova Energy Ltd	JRD	NI	0.58	0.00
Nova Energy Ltd	MKE	NI	0.55	0.00
Wellington Electricity Lines Ltd	WIL	NI	13.88	0.01
Waverly Wind Farm Ltd	WVY	NI	47.07	0.01

WEL Networks Ltd	TWH	NI	7.84	0.01

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