COMMERCE COMMISSION
NEW ZEALAND

# EDB Information Disclosure Requirements
# Information Templates
# for
## Schedules 1–10

| | |
|---|---|
| **Company Name** | Northpower Limited |
| **Disclosure Date** | 31 August 2022 |
| **Disclosure Year (year ended)** | 31 March 2022 |

**Templates for Schedules 1–10 excluding 5f–5g**
**Template Version 4.1. Prepared 21 December 2017**

## Table of Contents

## Disclosure Template Instructions

These templates have been prepared for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012.

### *Company Name and Dates*

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the 'For year ended' date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

### *Data Entry Cells and Calculated Cells*

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

### *Validation Settings on Data Entry Cells*

To maintain a consistency of format and to help guard against errors in data entry, some data entry cells test keyboard entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names, to values between 0% and 100%, or either a numeric entry or the text entry "N/A". Where this occurs, a validation message will appear when data is being entered. These checks are applied to keyboard entries only and not, for example, to entries made using Excel's copy and paste facility.

### *Conditional Formatting Settings on Data Entry Cells*

Schedule 2 cells G79 and I79:L79 will change colour if the total cashflows do not equal the corresponding values in table 2(ii).
Schedule 4 cells P99:P105 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).
Schedule 9b columns AA to AE (2013 to 2017) contain conditional formatting. The data entry cells for future years are hidden (are changed from white to yellow).
Schedule 9b cells AG10 to AG60 will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.
Schedule 9c cell G30 will change colour if G30 (overhead circuit length by terrain) does not equal G18 (overhead circuit length by operating voltage).

### *Inserting Additional Rows and Columns*

The templates for schedules 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.
Additional rows in schedules 5c, 6a, and 9e must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
Schedules 5d and 5e may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.
The template for schedule 8 may require additional columns to be inserted between column P and U. To avoid interfering with the title block entries, these should be inserted to the left of column S. If inserting additional columns, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The formulas can be found in the equivalent cells of the existing columns.

### *Disclosures by Sub-Network*
If the supplier has sub-networks, schedules 8, 9a, 9b, 9c, 9e, and 10 must be completed for the network and for each sub-network. A copy of the schedule worksheet(s) must be made for each sub-network and named accordingly.

### *Schedule References*
The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 21 December 2017). They provide a common reference between the rows in the determination and the template.

### *Description of Calculation References*
Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook.  Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

### *Worksheet Completion Sequence*
Calculation cells may show an incorrect value until precedent cell entries have been completed. Data entry may be assisted by completing the schedules in the following order:
1. Coversheet
2. Schedules 5a–5e
3. Schedules 6a–6b
4. Schedule 8
5. Schedule 3
6. Schedule 4
7. Schedule 2
8. Schedule 7
9. Schedules 9a–9e
10. Schedule 10

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

*7* **1(i): Expenditure metrics**

| sch ref | | Expenditure per GWh energy delivered to ICPs ($/GWh) | Expenditure per average no. of ICPs ($/ICP) | Expenditure per MW maximum coincident system demand ($/MW) | Expenditure per km circuit length ($/km) | Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA) |
|---|---|---|---|---|---|---|
| *8* | | | | | | |
| *9* | **Operational expenditure** | 27,533 | 463 | 157,674 | 4,665 | 48,831 |
| *10* | Network | 10,896 | 183 | 62,397 | 1,846 | 19,324 |
| *11* | Non-network | 16,637 | 280 | 95,276 | 2,819 | 29,507 |
| *12* | | | | | | |
| *13* | **Expenditure on assets** | 28,766 | 483 | 164,734 | 4,874 | 51,018 |
| *14* | Network | 27,444 | 461 | 157,163 | 4,650 | 48,673 |
| *15* | Non-network | 1,322 | 22 | 7,571 | 224 | 2,345 |
| *16* | | | | | | |

*17* **1(ii): Revenue metrics**

| sch ref | | Revenue per GWh energy delivered to ICPs ($/GWh) | Revenue per average no. of ICPs ($/ICP) |
|---|---|---|---|
| *18* | | | |
| *19* | **Total consumer line charge revenue** | 62,600 | 1,052 |
| *20* | Standard consumer line charge revenue | 98,272 | 916 |
| *21* | Non-standard consumer line charge revenue | 18,115 | 1,200,351 |
| *22* | | | |

*23* **1(iii): Service intensity measures**

| sch ref | | | |
|---|---|---|---|
| *24* | | | |
| *25* | Demand density | 30 | *Maximum coincident system demand per km of circuit length (for supply) (kW/km)* |
| *26* | Volume density | 169 | *Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)* |
| *27* | Connection point density | 10 | *Average number of ICPs per km of circuit length (for supply) (ICPs/km)* |
| *28* | Energy intensity | 16,800 | *Total energy delivered to ICPs per average number of ICPs (kWh/ICP)* |
| *29* | | | |

*30* **1(iv): Composition of regulatory income**

| sch ref | | ($000) | % of revenue |
|---|---|---|---|
| *31* | | | |
| *32* | Operational expenditure | 28,697 | 43.47% |
| *33* | Pass-through and recoverable costs excluding financial incentives and wash-ups | 17,703 | 26.82% |
| *34* | Total depreciation | 11,454 | 17.35% |
| *35* | Total revaluations | 20,647 | 31.28% |
| *36* | Regulatory tax allowance | 3,147 | 4.77% |
| *37* | Regulatory profit/(loss) including financial incentives and wash-ups | 25,663 | 38.87% |
| *38* | **Total regulatory income** | 66,016 | |
| *39* | | | |

*40* **1(v): Reliability**

| sch ref | | | |
|---|---|---|---|
| *41* | | | |
| *42* | Interruption rate | 14.65 | *Interruptions per 100 circuit km* |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | | | |
|---|---|---|---|---|---|
| *7* | **2(i): Return on Investment** | | **CY-2** | **CY-1** | **Current Year CY** |
| *8* | | | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| *9* | **ROI – comparable to a post tax WACC** | | **%** | **%** | **%** |
| *10* | Reflecting all revenue earned | | 3.35% | 2.96% | 8.46% |
| *11* | Excluding revenue earned from financial incentives | | 3.35% | 2.96% | 8.46% |
| *12* | Excluding revenue earned from financial incentives and wash-ups | | 3.35% | 2.96% | 8.46% |
| *13* | | | | | |
| *14* | **Mid-point estimate of post tax WACC** | | 4.27% | 3.72% | 3.52% |
| *15* | 25th percentile estimate | | 3.59% | 3.04% | 2.84% |
| *16* | 75th percentile estimate | | 4.95% | 4.40% | 4.20% |
| *17* | | | | | |
| *18* | | | | | |
| *19* | **ROI – comparable to a vanilla WACC** | | | | |
| *20* | Reflecting all revenue earned | | 3.77% | 3.29% | 8.76% |
| *21* | Excluding revenue earned from financial incentives | | 3.77% | 3.29% | 8.76% |
| *22* | Excluding revenue earned from financial incentives and wash-ups | | 3.77% | 3.29% | 8.76% |
| *23* | | | | | |
| *24* | **WACC rate used to set regulatory price path** | | | | |
| *25* | | | | | |
| *26* | **Mid-point estimate of vanilla WACC** | | 4.69% | 4.05% | 3.82% |
| *27* | 25th percentile estimate | | 4.01% | 3.37% | 3.14% |
| *28* | 75th percentile estimate | | 5.37% | 4.73% | 4.50% |
| *29* | | | | | |
| *30* | **2(ii): Information Supporting the ROI** | | | **($000)** | |
| *31* | | | | | |
| *32* | | Total opening RAB value | 298,438 | | |
| *33* | *plus* | Opening deferred tax | (12,459) | | |
| *34* | **Opening RIV** | | | 285,979 | |
| *35* | | | | | |
| *36* | **Line charge revenue** | | | 65,246 | |
| *37* | | | | | |
| *38* | | Expenses cash outflow | 46,400 | | |
| *39* | *add* | Assets commissioned | 20,879 | | |
| *40* | *less* | Asset disposals | 453 | | |
| *41* | *add* | Tax payments | 1,396 | | |
| *42* | *less* | Other regulated income | 770 | | |
| *43* | **Mid-year net cash outflows** | | | 67,451 | |
| *44* | | | | | |
| *45* | **Term credit spread differential allowance** | | | – | |
| *46* | | | | | |
| *47* | | Total closing RAB value | 328,448 | | |
| *48* | *less* | Adjustment resulting from asset allocation | 392 | | |
| *49* | *less* | Lost and found assets adjustment | – | | |
| *50* | *plus* | Closing deferred tax | (14,210) | | |
| *51* | **Closing RIV** | | | 313,847 | |
| *52* | | | | | |
| *53* | **ROI – comparable to a vanilla WACC** | | | | 8.76% |
| *54* | | | | | |
| *55* | | Leverage (%) | | | 42% |
| *56* | | Cost of debt assumption (%) | | | 2.55% |
| *57* | | Corporate tax rate (%) | | | 28% |
| *58* | | | | | |
| *59* | **ROI – comparable to a post tax WACC** | | | | 8.46% |
| *60* | | | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

### 2(iii): Information Supporting the Monthly ROI

| | |
|---|---|
| **Opening RIV** | N/A |

| | Line charge revenue | Expenses cash outflow | Assets commissioned | Asset disposals | Other regulated income | Monthly net cash outflows |
|---|---|---|---|---|---|---|
| April | | | | | | – |
| May | | | | | | – |
| June | | | | | | – |
| July | | | | | | – |
| August | | | | | | – |
| September | | | | | | – |
| October | | | | | | – |
| November | | | | | | – |
| December | | | | | | – |
| January | | | | | | – |
| February | | | | | | – |
| March | | | | | | – |
| **Total** | – | – | – | – | – | – |

| | |
|---|---|
| **Tax payments** | N/A |
| **Term credit spread differential allowance** | N/A |
| **Closing RIV** | N/A |
| **Monthly ROI – comparable to a vanilla WACC** | N/A |
| **Monthly ROI – comparable to a post tax WACC** | N/A |

### 2(iv): Year-End ROI Rates for Comparison Purposes

| | |
|---|---|
| **Year-end ROI – comparable to a vanilla WACC** | 8.66% |
| **Year-end ROI – comparable to a post tax WACC** | 8.36% |

** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

### 2(v): Financial Incentives and Wash-Ups

| | | |
|---|---|---|
| Net recoverable costs allowed under incremental rolling incentive scheme | – | |
| Purchased assets – avoided transmission charge | | |
| Energy efficiency and demand incentive allowance | | |
| Quality incentive adjustment | | |
| Other financial incentives | | |
| **Financial incentives** | | – |
| **Impact of financial incentives on ROI** | | – |
| Input methodology claw-back | | |
| CPP application recoverable costs | | |
| Catastrophic event allowance | | |
| Capex wash-up adjustment | | |
| Transmission asset wash-up adjustment | | |
| 2013–15 NPV wash-up allowance | | |
| Reconsideration event allowance | | |
| Other wash-ups | | |
| **Wash-up costs** | | – |
| **Impact of wash-up costs on ROI** | | – |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | ($000) |
|---|---|---|---|
| *7* | | **3(i): Regulatory Profit** | **($000)** |
| *8* | | **Income** | |
| *9* | | Line charge revenue | 65,246 |
| *10* | *plus* | Gains / (losses) on asset disposals | |
| *11* | *plus* | Other regulated income (other than gains / (losses) on asset disposals) | 770 |
| *12* | | | |
| *13* | | **Total regulatory income** | 66,016 |
| *14* | | **Expenses** | |
| *15* | *less* | Operational expenditure | 28,697 |
| *16* | | | |
| *17* | *less* | Pass-through and recoverable costs excluding financial incentives and wash-ups | 17,703 |
| *18* | | | |
| *19* | | **Operating surplus / (deficit)** | 19,616 |
| *20* | | | |
| *21* | *less* | Total depreciation | 11,454 |
| *22* | | | |
| *23* | *plus* | Total revaluations | 20,647 |
| *24* | | | |
| *25* | | **Regulatory profit / (loss) before tax** | 28,810 |
| *26* | | | |
| *27* | *less* | Term credit spread differential allowance | – |
| *28* | | | |
| *29* | *less* | Regulatory tax allowance | 3,147 |
| *30* | | | |
| *31* | | **Regulatory profit/(loss) including financial incentives and wash-ups** | 25,663 |
| *32* | | | |

| *sch ref* | | ($000) | |
|---|---|---|---|
| *33* | **3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups** | **($000)** | |
| *34* | **Pass through costs** | | |
| *35* | Rates | 113 | |
| *36* | Commerce Act levies | 68 | |
| *37* | Industry levies | 238 | |
| *38* | CPP specified pass through costs | | |
| *39* | **Recoverable costs excluding financial incentives and wash-ups** | | |
| *40* | Electricity lines service charge payable to Transpower | 16,339 | |
| *41* | Transpower new investment contract charges | | |
| *42* | System operator services | | |
| *43* | Distributed generation allowance | 945 | |
| *44* | Extended reserves allowance | | |
| *45* | Other recoverable costs excluding financial incentives and wash-ups | | |
| *46* | **Pass-through and recoverable costs excluding financial incentives and wash-ups** | | 17,703 |
| *47* | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | | |
|---|---|---|---|---|
| *48* | **3(iii): Incremental Rolling Incentive Scheme** | | **($000)** | |
| *49* | | | **CY-1** | **CY** |
| *50* | | | **31 Mar 21** | **31 Mar 22** |
| *51* | Allowed controllable opex | | | |
| *52* | Actual controllable opex | | | |
| *53* | | | | |
| *54* | Incremental change in year | | | |
| *55* | | | | |
| *56* | | | **Previous years' incremental change** | **Previous years' incremental change adjusted for inflation** |
| *57* | CY-5 | 31 Mar 17 | | |
| *58* | CY-4 | 31 Mar 18 | | |
| *59* | CY-3 | 31 Mar 19 | | |
| *60* | CY-2 | 31 Mar 20 | | |
| *61* | CY-1 | 31 Mar 21 | | |
| *62* | **Net incremental rolling incentive scheme** | | | – |
| *63* | | | | |
| *64* | **Net recoverable costs allowed under incremental rolling incentive scheme** | | | – |
| *65* | **3(iv): Merger and Acquisition Expenditure** | | | |
| *70* | | | | **($000)** |
| *66* | Merger and acquisition expenditure | | | |
| *67* | | | | |
| *68* | *Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)* | | | |
| *69* | **3(v): Other Disclosures** | | | |
| *70* | | | | **($000)** |
| *71* | Self-insurance allowance | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

## 4(i): Regulatory Asset Base Value (Rolled Forward)

| | | RAB | RAB | RAB | RAB | RAB |
|---|---|---|---|---|---|---|
| | for year ended | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| | | **($000)** | **($000)** | **($000)** | **($000)** | **($000)** |
| | **Total opening RAB value** | 258,435 | 262,813 | 267,167 | 279,361 | 298,438 |
| *less* | **Total depreciation** | 10,016 | 10,169 | 9,962 | 10,574 | 11,454 |
| *plus* | **Total revaluations** | 2,840 | 3,897 | 6,765 | 4,241 | 20,647 |
| *plus* | **Assets commissioned** | 11,619 | 12,121 | 16,089 | 24,903 | 20,879 |
| *less* | **Asset disposals** | 65 | 42 | 57 | 29 | 453 |
| *plus* | **Lost and found assets adjustment** | – | – | – | – | – |
| *plus* | **Adjustment resulting from asset allocation** | – | (1,453) | (642) | 536 | 392 |
| | **Total closing RAB value** | 262,813 | 267,167 | 279,361 | 298,438 | 328,448 |

## 4(ii): Unallocated Regulatory Asset Base

| | | Unallocated RAB * | | RAB | |
|---|---|---|---|---|---|
| | | **($000)** | **($000)** | **($000)** | **($000)** |
| | **Total opening RAB value** | | 301,070 | | 298,438 |
| *less* | | | | | |
| | **Total depreciation** | | 11,558 | | 11,454 |
| *plus* | | | | | |
| | **Total revaluations** | | 20,830 | | 20,647 |
| *plus* | | | | | |
| | Assets commissioned (other than below) | 4,763 | | 4,763 | |
| | Assets acquired from a regulated supplier | – | | – | |
| | Assets acquired from a related party | 16,116 | | 16,116 | |
| | **Assets commissioned** | | 20,879 | | 20,879 |
| *less* | | | | | |
| | Asset disposals (other than below) | 453 | | 453 | |
| | Asset disposals to a regulated supplier | | | | |
| | Asset disposals to a related party | | | | |
| | **Asset disposals** | | 453 | | 453 |
| *plus* | **Lost and found assets adjustment** | | | | |
| *plus* | **Adjustment resulting from asset allocation** | | | | 392 |
| | **Total closing RAB value** | | 330,767 | | 328,448 |

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | | | | |
|---|---|---|---|---|---|---|
| *51* | | | | | | |
| *52* | **4(iii): Calculation of Revaluation Rate and Revaluation of Assets** | | | | | |
| *53* | | | | | | |
| *54* | | $CPI_4$ | | | | 1,142 |
| *55* | | $CPI_4^{-4}$ | | | | 1,068 |
| *56* | | Revaluation rate (%) | | | | 6.93% |
| *57* | | | | | | |
| *58* | | | **Unallocated RAB *** | | **RAB** | |
| *59* | | | **($000)** | **($000)** | **($000)** | **($000)** |
| *60* | | Total opening RAB value | 301,070 | | 298,438 | |
| *61* | *less* | Opening value of fully depreciated, disposed and lost assets | 449 | | 449 | |
| *62* | | | | | | |
| *63* | | Total opening RAB value subject to revaluation | 300,621 | | 297,989 | |
| *64* | | **Total revaluations** | | 20,830 | | 20,647 |
| *65* | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| *66* | **4(iv): Roll Forward of Works Under Construction** | | | | | |
| *67* | | | **Unallocated works under construction** | | **Allocated works under construction** | |
| *68* | | **Works under construction—preceding disclosure year** | | 6,421 | | 6,421 |
| *69* | *plus* | Capital expenditure | 22,755 | | 22,832 | |
| *70* | *less* | Assets commissioned | 20,879 | | 20,879 | |
| *71* | *plus* | Adjustment resulting from asset allocation | | | | |
| *72* | | **Works under construction - current disclosure year** | | 8,297 | | 8,375 |
| *73* | | | | | | |
| *74* | | Highest rate of capitalised finance applied | | | | 2.46% |
| *75* | | | | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

76 **4(v): Regulatory Depreciation**

| sch ref | | Unallocated RAB * | | RAB | |
|---|---|---|---|---|---|
| 78 | | ($000) | ($000) | ($000) | ($000) |
| 79 | Depreciation - standard | 10,764 | | 10,668 | |
| 80 | Depreciation - no standard life assets | 795 | | 786 | |
| 81 | Depreciation - modified life assets | | | | |
| 82 | Depreciation - alternative depreciation in accordance with CPP | | | | |
| 83 | **Total depreciation** | | 11,558 | | 11,454 |
| 84 | | | | | |

85 **4(vi): Disclosure of Changes to Depreciation Profiles**

($000 unless otherwise specified)

| sch ref | Asset or assets with changes to depreciation* | Reason for non-standard depreciation (text entry) | Depreciation charge for the period (RAB) | Closing RAB value under 'non-standard' depreciation | Closing RAB value under 'standard' depreciation |
|---|---|---|---|---|---|
| 87 | | | | | |
| 88 | | | | | |
| 89 | | | | | |
| 90 | | | | | |
| 91 | | | | | |
| 92 | | | | | |
| 93 | | | | | |
| 94 | | | | | |

95 ** include additional rows if needed*

96 **4(vii): Disclosure by Asset Category**

97 ($000 unless otherwise specified)

| sch ref | | | Subtransmission lines | Subtransmission cables | Zone substations | Distribution and LV lines | Distribution and LV cables | Distribution substations and transformers | Distribution switchgear | Other network assets | Non-network assets | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 99 | | **Total opening RAB value** | 7,766 | 9,964 | 32,844 | 121,371 | 49,828 | 44,464 | 7,734 | 8,116 | 16,350 | 298,438 |
| 100 | *less* | Total depreciation | 356 | 289 | 1,321 | 4,085 | 1,767 | 1,596 | 345 | 910 | 786 | 11,454 |
| 101 | *plus* | Total revaluations | 538 | 690 | 2,276 | 8,409 | 3,453 | 3,081 | 536 | 562 | 1,102 | 20,647 |
| 102 | *plus* | Assets commissioned | – | – | 949 | 6,929 | 1,024 | 7,968 | 986 | 251 | 2,772 | 20,879 |
| 103 | *less* | Asset disposals | – | – | – | – | – | 98 | – | – | 355 | 453 |
| 104 | *plus* | Lost and found assets adjustment | – | – | – | – | – | – | – | – | – | – |
| 105 | *plus* | Adjustment resulting from asset allocation | (4) | – | – | – | 5 | – | – | – | 391 | 392 |
| 106 | *plus* | Asset category transfers | – | – | – | – | – | – | – | – | – | – |
| 107 | | **Total closing RAB value** | 7,945 | 10,366 | 34,749 | 132,625 | 52,543 | 53,819 | 8,911 | 8,019 | 19,473 | 328,448 |
| 108 | | | | | | | | | | | | |
| 109 | | **Asset Life** | | | | | | | | | | |
| 110 | | Weighted average remaining asset life | 34.0 | 39.1 | 32.8 | 41.1 | 32.4 | 34.3 | 26.2 | 14.2 | 26.9 | (years) |
| 111 | | Weighted average expected total asset life | 53.6 | 57.6 | 45.8 | 59.3 | 47.3 | 45.0 | 37.7 | 19.1 | 33.0 | (years) |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
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# SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

| *sch ref* | | | | | |
|---|---|---|---|---|---|
| *7* | | **5a(i): Regulatory Tax Allowance** | | | **($000)** |
| *8* | | **Regulatory profit / (loss) before tax** | | | 28,810 |
| *9* | | | | | |
| *10* | *plus* | Income not included in regulatory profit / (loss) before tax but taxable | | * | |
| *11* | | Expenditure or loss in regulatory profit / (loss) before tax but not deductible | 12 | * | |
| *12* | | Amortisation of initial differences in asset values | 4,536 | | |
| *13* | | Amortisation of revaluations | 1,552 | | |
| *14* | | | | | 6,100 |
| *15* | | | | | |
| *16* | *less* | Total revaluations | 20,647 | | |
| *17* | | Income included in regulatory profit / (loss) before tax but not taxable | | * | |
| *18* | | Discretionary discounts and customer rebates | | | |
| *19* | | Expenditure or loss deductible but not in regulatory profit / (loss) before tax | | * | |
| *20* | | Notional deductible interest | 3,025 | | |
| *21* | | | | | 23,672 |
| *22* | | | | | |
| *23* | | **Regulatory taxable income** | | | 11,238 |
| *24* | | | | | |
| *25* | *less* | Utilised tax losses | | | |
| *26* | | Regulatory net taxable income | | | 11,238 |
| *27* | | | | | |
| *28* | | Corporate tax rate (%) | 28% | | |
| *29* | | **Regulatory tax allowance** | | | 3,147 |
| *30* | | | | | |
| *31* | * | Workings to be provided in Schedule 14 | | | |
| *32* | | **5a(ii): Disclosure of Permanent Differences** | | | |
| *33* | | In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i). | | | |
| *34* | | **5a(iii): Amortisation of Initial Difference in Asset Values** | | | **($000)** |
| *35* | | | | | |
| *36* | | Opening unamortised initial differences in asset values | 96,535 | | |
| *37* | *less* | Amortisation of initial differences in asset values | 4,536 | | |
| *38* | *plus* | Adjustment for unamortised initial differences in assets acquired | | | |
| *39* | *less* | Adjustment for unamortised initial differences in assets disposed | | | |
| *40* | | Closing unamortised initial differences in asset values | | | 91,999 |
| *41* | | | | | |
| *42* | | Opening weighted average remaining useful life of relevant assets (years) | | | 21 |
| *43* | | | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

| *sch ref* | | | | |
|---|---|---|---|---|
| 44 | **5a(iv): Amortisation of Revaluations** | | | **($000)** |
| 45 | | | | |
| 46 | | Opening sum of RAB values without revaluations | 263,537 | |
| 47 | | | | |
| 48 | | Adjusted depreciation | 9,902 | |
| 49 | | Total depreciation | 11,454 | |
| 50 | | Amortisation of revaluations | | 1,552 |
| 51 | | | | |
| 52 | **5a(v): Reconciliation of Tax Losses** | | | **($000)** |
| 53 | | | | |
| 54 | | **Opening tax losses** | | |
| 55 | *plus* | Current period tax losses | | |
| 56 | *less* | Utilised tax losses | | |
| 57 | | **Closing tax losses** | | – |
| 58 | **5a(vi): Calculation of Deferred Tax Balance** | | | **($000)** |
| 59 | | | | |
| 60 | | **Opening deferred tax** | (12,459) | |
| 61 | | | | |
| 62 | *plus* | Tax effect of adjusted depreciation | 2,773 | |
| 63 | | | | |
| 64 | *less* | Tax effect of tax depreciation | 3,326 | |
| 65 | | | | |
| 66 | *plus* | Tax effect of other temporary differences* | (8) | |
| 67 | | | | |
| 68 | *less* | Tax effect of amortisation of initial differences in asset values | 1,270 | |
| 69 | | | | |
| 70 | *plus* | Deferred tax balance relating to assets acquired in the disclosure year | | |
| 71 | | | | |
| 72 | *less* | Deferred tax balance relating to assets disposed in the disclosure year | (127) | |
| 73 | | | | |
| 74 | *plus* | Deferred tax cost allocation adjustment | (46) | |
| 75 | | | | |
| 76 | | **Closing deferred tax** | | (14,210) |
| 77 | | | | |
| 78 | **5a(vii): Disclosure of Temporary Differences** | | | |
| 79 | | *In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).* | | |
| 80 | | | | |
| 81 | **5a(viii): Regulatory Tax Asset Base Roll-Forward** | | | |
| 82 | | | | **($000)** |
| 83 | | **Opening sum of regulatory tax asset values** | 123,714 | |
| 84 | *less* | Tax depreciation | 11,878 | |
| 85 | *plus* | Regulatory tax asset value of assets commissioned | 20,453 | |
| 86 | *less* | Regulatory tax asset value of asset disposals | | |
| 87 | *plus* | Lost and found assets adjustment | | |
| 88 | *plus* | Adjustment resulting from asset allocation | 227 | |
| 89 | *plus* | Other adjustments to the RAB tax value | | |
| 90 | | **Closing sum of regulatory tax asset values** | | 132,516 |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the ID determination), and so is subject to the assurance report required by clause 2.8.

| *sch ref* | | | |
|---|---|---|---|
| 7 | **5b(i): Summary—Related Party Transactions** | **($000)** | **($000)** |
| 8 | **Total regulatory income** | | |
| 9 | | | |
| 10 | **Market value of asset disposals** | | |
| 11 | | | |
| 12 | Service interruptions and emergencies | 3,124 | |
| 13 | Vegetation management | 2,448 | |
| 14 | Routine and corrective maintenance and inspection | 3,653 | |
| 15 | Asset replacement and renewal (opex) | 1,855 | |
| 16 | **Network opex** | | 11,081 |
| 17 | Business support | 20 | |
| 18 | System operations and network support | 194 | |
| 19 | **Operational expenditure** | | 11,294 |
| 20 | Consumer connection | 1,433 | |
| 21 | System growth | 127 | |
| 22 | Asset replacement and renewal (capex) | 14,763 | |
| 23 | Asset relocations | 517 | |
| 24 | Quality of supply | 44 | |
| 25 | Legislative and regulatory | – | |
| 26 | Other reliability, safety and environment | 148 | |
| 27 | **Expenditure on non-network assets** | | (2) |
| 28 | **Expenditure on assets** | | 17,029 |
| 29 | Cost of financing | | |
| 30 | Value of capital contributions | | |
| 31 | Value of vested assets | | |
| 32 | **Capital Expenditure** | | 17,029 |
| 33 | **Total expenditure** | | 28,324 |
| 34 | | | |
| 35 | **Other related party transactions** | | |

## 36 5b(iii): Total Opex and Capex Related Party Transactions

| *sch ref* | **Name of related party** | **Nature of opex or capex service provided** | **Total value of transactions ($000)** |
|---|---|---|---|
| 38 | Northpower Contracting Division | Service interruptions and emergencies | 3,124 |
| 39 | Northpower Contracting Division | Vegetation management | 2,448 |
| 40 | Northpower Contracting Division | Routine and corrective maintenance and inspection | 3,653 |
| 41 | Northpower Contracting Division | Asset replacement and renewal (opex) | 1,855 |
| 42 | Northpower Contracting Division | System operations and network support | 170 |
| 43 | Northpower Fibre Limited | System operations and network support | 24 |
| 44 | Electricity Engineers' Association | Business support | 20 |
| 45 | Northpower Contracting Division | Asset relocations | 517 |
| 46 | Northpower Contracting Division | Consumer connection | 1,433 |
| 47 | Northpower Contracting Division | Asset replacement and renewal (capex) | 14,763 |
| 48 | Northpower Contracting Division | Quality of supply | 44 |
| 49 | Northpower Contracting Division | Other reliability, safety and environment | 148 |
| 50 | Northpower Contracting Division | System growth | 127 |
| 51 | Northpower Contracting Division | Expenditure on non-network assets | (2) |
| 52 | | [Select one] | |
| 53 | **Total value of related party transactions** | | 28,324 |

54 ** include additional rows if needed*
55

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

7

8 ## 5c(i): Qualifying Debt (may be Commission only)

9

| sch ref | Issuing party | Issue date | Pricing date | Original tenor (in years) | Coupon rate (%) | Book value at issue date (NZD) | Book value at date of financial statements (NZD) | Term Credit Spread Difference | Debt issue cost readjustment |
|---|---|---|---|---|---|---|---|---|---|
| 11 | | | | | | | | | |
| 12 | | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | | | | | | | | | |
| 16 | ** include additional rows if needed* | | | | | | – | – | – |

17

18 ## 5c(ii): Attribution of Term Credit Spread Differential

19

| sch ref | | | |
|---|---|---|---|
| 20 | **Gross term credit spread differential** | | – |
| 21 | | | |
| 22 | Total book value of interest bearing debt | | |
| 23 | Leverage | 42% | |
| 24 | Average opening and closing RAB values | | |
| 25 | **Attribution Rate (%)** | | – |
| 26 | | | |
| 27 | **Term credit spread differential allowance** | | – |

Company Name: **Northpower Limited**
For Year Ended: **31 March 2022**

# SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| sch ref | | Arm's length deduction | Value allocated ($000s) Electricity distribution services | Non-electricity distribution services | Total | OVABAA allocation increase ($000s) |
|---|---|---|---|---|---|---|
| 7 | **5d(i): Operating Cost Allocations** | | | | | |
| 10 | **Service interruptions and emergencies** | | | | | |
| 11 | Directly attributable | | 3,125 | | | |
| 12 | Not directly attributable | | | | – | |
| 13 | **Total attributable to regulated service** | | 3,125 | | | |
| 14 | **Vegetation management** | | | | | |
| 15 | Directly attributable | | 2,574 | | | |
| 16 | Not directly attributable | | | | – | |
| 17 | **Total attributable to regulated service** | | 2,574 | | | |
| 18 | **Routine and corrective maintenance and inspection** | | | | | |
| 19 | Directly attributable | | 3,700 | | | |
| 20 | Not directly attributable | | | | – | |
| 21 | **Total attributable to regulated service** | | 3,700 | | | |
| 22 | **Asset replacement and renewal** | | | | | |
| 23 | Directly attributable | | 1,957 | | | |
| 24 | Not directly attributable | | | | – | |
| 25 | **Total attributable to regulated service** | | 1,957 | | | |
| 26 | **System operations and network support** | | | | | |
| 27 | Directly attributable | | 3,690 | | | |
| 28 | Not directly attributable | | | | – | |
| 29 | **Total attributable to regulated service** | | 3,690 | | | |
| 30 | **Business support** | | | | | |
| 31 | Directly attributable | | 5,740 | | | |
| 32 | Not directly attributable | | 7,910 | 19,523 | 27,433 | |
| 33 | **Total attributable to regulated service** | | 13,650 | | | |
| 34 | | | | | | |
| 35 | **Operating costs directly attributable** | | 20,787 | | | |
| 36 | **Operating costs not directly attributable** | – | 7,910 | 19,523 | 27,433 | – |
| 37 | **Operational expenditure** | | 28,697 | | | |
| 38 | | | | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

*sch ref*

## 5d(ii): Other Cost Allocations

| | ($000) |
|---|---|
| **Pass through and recoverable costs** | |
| **Pass through costs** | |
| Directly attributable | 419 |
| Not directly attributable | |
| **Total attributable to regulated service** | 419 |
| **Recoverable costs** | |
| Directly attributable | 17,284 |
| Not directly attributable | |
| **Total attributable to regulated service** | 17,284 |

## 5d(iii): Changes in Cost Allocations* †

| **Change in cost allocation 1** | | | CY-1 ($000) | Current Year (CY) ($000) |
|---|---|---|---|---|
| Cost category | Business Support - Finance Costs | Original allocation | 1,586 | 1,450 |
| Original allocator or line items | Gross Margin % | New allocation | 1,012 | 975 |
| New allocator or line items | Gross Margin $ | Difference | 574 | 475 |
| Rationale for change | The new allocator more closely reflects the split of resource on finance activities. | | | |

| **Change in cost allocation 2** | | | CY-1 ($000) | Current Year (CY) ($000) |
|---|---|---|---|---|
| Cost category | | Original allocation | | |
| Original allocator or line items | | New allocation | | |
| New allocator or line items | | Difference | – | – |
| Rationale for change | | | | |

| **Change in cost allocation 3** | | | CY-1 ($000) | Current Year (CY) ($000) |
|---|---|---|---|---|
| Cost category | | Original allocation | | |
| Original allocator or line items | | New allocation | | |
| New allocator or line items | | Difference | – | – |
| Rationale for change | | | | |

** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*
*† include additional rows if needed*

| | |
|---|---|
| Company Name | Northpower Limited |
| For Year Ended | 31 March 2022 |

## SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.
EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| sch ref | | Value allocated ($000s) Electricity distribution services |
|---|---|---|
| 7 | **5e(i): Regulated Service Asset Values** | |
| 8 | | Value allocated ($000s) |
| 9 | | Electricity distribution services |
| 10 | **Subtransmission lines** | |
| 11 | Directly attributable | 7,590 |
| 12 | Not directly attributable | 355 |
| 13 | **Total attributable to regulated service** | 7,945 |
| 14 | **Subtransmission cables** | |
| 15 | Directly attributable | 10,366 |
| 16 | Not directly attributable | |
| 17 | **Total attributable to regulated service** | 10,366 |
| 18 | **Zone substations** | |
| 19 | Directly attributable | 34,749 |
| 20 | Not directly attributable | |
| 21 | **Total attributable to regulated service** | 34,749 |
| 22 | **Distribution and LV lines** | |
| 23 | Directly attributable | 128,679 |
| 24 | Not directly attributable | 3,945 |
| 25 | **Total attributable to regulated service** | 132,625 |
| 26 | **Distribution and LV cables** | |
| 27 | Directly attributable | 52,543 |
| 28 | Not directly attributable | |
| 29 | **Total attributable to regulated service** | 52,543 |
| 30 | **Distribution substations and transformers** | |
| 31 | Directly attributable | 53,819 |
| 32 | Not directly attributable | |
| 33 | **Total attributable to regulated service** | 53,819 |
| 34 | **Distribution switchgear** | |
| 35 | Directly attributable | 8,911 |
| 36 | Not directly attributable | |
| 37 | **Total attributable to regulated service** | 8,911 |
| 38 | **Other network assets** | |
| 39 | Directly attributable | 6,717 |
| 40 | Not directly attributable | 1,302 |
| 41 | **Total attributable to regulated service** | 8,019 |
| 42 | **Non-network assets** | |
| 43 | Directly attributable | 14,156 |
| 44 | Not directly attributable | 5,317 |
| 45 | **Total attributable to regulated service** | 19,473 |
| 46 | | |
| 47 | **Regulated service asset value directly attributable** | 317,529 |
| 48 | **Regulated service asset value not directly attributable** | 10,920 |
| 49 | **Total closing RAB value** | 328,448 |
| 50 | | |

| sch ref | | | | CY-1 | Current Year (CY) |
|---|---|---|---|---|---|
| 51 | **5e(ii): Changes in Asset Allocations* †** | | | | |
| 52 | | | | ($000) | |
| 53 | **Change in asset value allocation 1** | | | **CY-1** | **Current Year (CY)** |
| 54 | Asset category | | Original allocation | | |
| 55 | Original allocator or line items | | New allocation | | |
| 56 | New allocator or line items | | Difference | – | – |
| 57 | | | | | |
| 58 | Rationale for change | | | | |
| 59 | | | | | |
| 60 | | | | | |
| 61 | | | | ($000) | |
| 62 | **Change in asset value allocation 2** | | | **CY-1** | **Current Year (CY)** |
| 63 | Asset category | | Original allocation | | |
| 64 | Original allocator or line items | | New allocation | | |
| 65 | New allocator or line items | | Difference | – | – |
| 66 | | | | | |
| 67 | Rationale for change | | | | |
| 68 | | | | | |
| 69 | | | | | |
| 70 | | | | ($000) | |
| 71 | **Change in asset value allocation 3** | | | **CY-1** | **Current Year (CY)** |
| 72 | Asset category | | Original allocation | | |
| 73 | Original allocator or line items | | New allocation | | |
| 74 | New allocator or line items | | Difference | – | – |
| 75 | | | | | |
| 76 | Rationale for change | | | | |
| 77 | | | | | |
| 78 | | | | | |

79 ** a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*
80 *† include additional rows if needed*

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | | |
|---|---|---|---|---|
| 7 | | **6a(i): Expenditure on Assets** | **($000)** | **($000)** |
| 8 | | Consumer connection | | 7,446 |
| 9 | | System growth | | 1,788 |
| 10 | | Asset replacement and renewal | | 18,022 |
| 11 | | Asset relocations | | 553 |
| 12 | | Reliability, safety and environment: | | |
| 13 | | Quality of supply | 51 | |
| 14 | | Legislative and regulatory | 20 | |
| 15 | | Other reliability, safety and environment | 723 | |
| 16 | | **Total reliability, safety and environment** | | 795 |
| 17 | | **Expenditure on network assets** | | 28,604 |
| 18 | | Expenditure on non-network assets | | 1,378 |
| 19 | | | | |
| 20 | | **Expenditure on assets** | | 29,982 |
| 21 | *plus* | Cost of financing | | 190 |
| 22 | *less* | Value of capital contributions | | 7,339 |
| 23 | *plus* | Value of vested assets | | |
| 24 | | | | |
| 25 | | **Capital expenditure** | | 22,832 |
| 26 | | **6a(ii): Subcomponents of Expenditure on Assets (where known)** | | **($000)** |
| 27 | | Energy efficiency and demand side management, reduction of energy losses | | |
| 28 | | Overhead to underground conversion | | |
| 29 | | Research and development | | |
| 30 | | **6a(iii): Consumer Connection** | | |
| 31 | | *Consumer types defined by EDB** | **($000)** | **($000)** |
| 32 | | All customer types | 7,446 | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | ** include additional rows if needed* | | |
| 38 | | **Consumer connection expenditure** | | 7,446 |
| 39 | | | | |
| 40 | *less* | Capital contributions funding consumer connection expenditure | 7,339 | |
| 41 | | **Consumer connection less capital contributions** | | 107 |
| 42 | | **6a(iv): System Growth and Asset Replacement and Renewal** | | **Asset** |
| 43 | | | **System Growth** | **Replacement and Renewal** |
| 44 | | | **($000)** | **($000)** |
| 45 | | Subtransmission | | |
| 46 | | Zone substations | 1,035 | 6,772 |
| 47 | | Distribution and LV lines | 603 | 7,568 |
| 48 | | Distribution and LV cables | 25 | 343 |
| 49 | | Distribution substations and transformers | 125 | 1,341 |
| 50 | | Distribution switchgear | | 2 |
| 51 | | Other network assets | | 1,996 |
| 52 | | **System growth and asset replacement and renewal expenditure** | 1,788 | 18,022 |
| 53 | *less* | Capital contributions funding system growth and asset replacement and renewal | | |
| 54 | | **System growth and asset replacement and renewal less capital contributions** | 1,788 | 18,022 |
| 55 | | | | |
| 56 | | **6a(v): Asset Relocations** | | |
| 57 | | *Project or programme** | **($000)** | **($000)** |
| 58 | | Manuka Place | 24 | |
| 59 | | Ground Mounted Sub | 388 | |
| 60 | | Minor relocations | 38 | |
| 61 | | Overhead to underground | 104 | |
| 62 | | | | |
| 63 | | ** include additional rows if needed* | | |
| 64 | | All other projects or programmes - asset relocations | | |
| 65 | | **Asset relocations expenditure** | | 553 |
| 66 | *less* | Capital contributions funding asset relocations | | |
| 67 | | **Asset relocations less capital contributions** | | 553 |

| | |
|---|---|
| Company Name | **Northpower Limited** |
| For Year Ended | **31 March 2022** |

## SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | ($000) | ($000) |
|---|---|---|---|---|
| 68 | | | | |
| 69 | **6a(vi): Quality of Supply** | | | |
| 70 | | *Project or programme** | **($000)** | **($000)** |
| 71 | | Comms for remote control | 51 | |
| 72 | | | | |
| 73 | | | | |
| 74 | | | | |
| 75 | | | | |
| 76 | | ** include additional rows if needed* | | |
| 77 | | All other projects programmes - quality of supply | | |
| 78 | | **Quality of supply expenditure** | | 51 |
| 79 | *less* | Capital contributions funding quality of supply | | |
| 80 | | **Quality of supply less capital contributions** | | 51 |
| 81 | **6a(vii): Legislative and Regulatory** | | | |
| 82 | | *Project or programme** | **($000)** | **($000)** |
| 83 | | Zone subsation risk mitigation | 20 | |
| 84 | | | | |
| 85 | | | | |
| 86 | | | | |
| 87 | | | | |
| 88 | | ** include additional rows if needed* | | |
| 89 | | All other projects or programmes - legislative and regulatory | | |
| 90 | | **Legislative and regulatory expenditure** | | 20 |
| 91 | *less* | Capital contributions funding legislative and regulatory | | |
| 92 | | **Legislative and regulatory less capital contributions** | | 20 |
| 93 | **6a(viii): Other Reliability, Safety and Environment** | | | |
| 94 | | *Project or programme** | **($000)** | **($000)** |
| 95 | | Zone subsation transformer upgrade | 346 | |
| 96 | | Zone subsation security improvements | 86 | |
| 97 | | Long and Crawford GMS replacement | 58 | |
| 98 | | Other Reliability Safety and Environment projects | 234 | |
| 99 | | | | |
| 100 | | ** include additional rows if needed* | | |
| 101 | | All other projects or programmes - other reliability, safety and environment | | |
| 102 | | **Other reliability, safety and environment expenditure** | | 723 |
| 103 | *less* | Capital contributions funding other reliability, safety and environment | | |
| 104 | | **Other reliability, safety and environment less capital contributions** | | 723 |
| 105 | | | | |
| 106 | **6a(ix): Non-Network Assets** | | | |
| 107 | | **Routine expenditure** | | |
| 108 | | *Project or programme** | **($000)** | **($000)** |
| 109 | | Leased Assets - Vehicles | 129 | |
| 110 | | | | |
| 111 | | | | |
| 112 | | | | |
| 113 | | | | |
| 114 | | ** include additional rows if needed* | | |
| 115 | | All other projects or programmes - routine expenditure | | |
| 116 | | **Routine expenditure** | | 129 |
| 117 | | **Atypical expenditure** | | |
| 118 | | *Project or programme** | **($000)** | **($000)** |
| 119 | | Asset Data Management System (ADMS) | 1,106 | |
| 120 | | Faults Management System | 143 | |
| 121 | | | | |
| 122 | | | | |
| 123 | | | | |
| 124 | | ** include additional rows if needed* | | |
| 125 | | All other projects or programmes - atypical expenditure | | |
| 126 | | **Atypical expenditure** | | 1,249 |
| 127 | | | | |
| 128 | | **Expenditure on non-network assets** | | 1,378 |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | |
|---|---|---|---|
| 7 | **6b(i): Operational Expenditure** | **($000)** | **($000)** |
| 8 | Service interruptions and emergencies | 3,125 | |
| 9 | Vegetation management | 2,574 | |
| 10 | Routine and corrective maintenance and inspection | 3,700 | |
| 11 | Asset replacement and renewal | 1,957 | |
| 12 | **Network opex** | | 11,356 |
| 13 | System operations and network support | 3,690 | |
| 14 | Business support | 13,650 | |
| 15 | **Non-network opex** | | 17,340 |
| 16 | | | |
| 17 | **Operational expenditure** | | 28,697 |
| 18 | **6b(ii): Subcomponents of Operational Expenditure (where known)** | | |
| 19 | Energy efficiency and demand side management, reduction of energy losses | | |
| 20 | Direct billing* | | |
| 21 | Research and development | | |
| 22 | Insurance | | |
| 23 | ** Direct billing expenditure by suppliers that directly bill the majority of their consumers* | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

# SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures

| *sch ref* | | | | |
|---|---|---|---|---|
| *7* | **7(i): Revenue** | **Target ($000) [1]** | **Actual ($000)** | **% variance** |
| *8* | Line charge revenue | 61,500 | 65,246 | 6% |
| *9* | **7(ii): Expenditure on Assets** | **Forecast ($000) [2]** | **Actual ($000)** | **% variance** |
| *10* | Consumer connection | 4,760 | 7,446 | 56% |
| *11* | System growth | 1,670 | 1,788 | 7% |
| *12* | Asset replacement and renewal | 18,933 | 18,022 | (5%) |
| *13* | Asset relocations | 105 | 553 | 427% |
| *14* | Reliability, safety and environment: | | | |
| *15* | Quality of supply | 1,710 | 51 | (97%) |
| *16* | Legislative and regulatory | | 20 | – |
| *17* | Other reliability, safety and environment | 530 | 723 | 36% |
| *18* | **Total reliability, safety and environment** | 2,240 | 795 | (65%) |
| *19* | **Expenditure on network assets** | 27,708 | 28,604 | 3% |
| *20* | Expenditure on non-network assets | 3,175 | 1,378 | (57%) |
| *21* | Expenditure on assets | 30,883 | 29,982 | (3%) |
| *22* | **7(iii): Operational Expenditure** | | | |
| *23* | Service interruptions and emergencies | 2,742 | 3,125 | 14% |
| *24* | Vegetation management | 2,889 | 2,574 | (11%) |
| *25* | Routine and corrective maintenance and inspection | 3,438 | 3,700 | 8% |
| *26* | Asset replacement and renewal | 2,569 | 1,957 | (24%) |
| *27* | **Network opex** | 11,638 | 11,356 | (2%) |
| *28* | System operations and network support | 3,050 | 3,690 | 21% |
| *29* | Business support | 13,194 | 13,650 | 3% |
| *30* | **Non-network opex** | 16,244 | 17,340 | 7% |
| *31* | **Operational expenditure** | 27,882 | 28,697 | 3% |
| *32* | **7(iv): Subcomponents of Expenditure on Assets (where known)** | | | |
| *33* | Energy efficiency and demand side management, reduction of energy losses | | – | – |
| *34* | Overhead to underground conversion | | – | – |
| *35* | Research and development | | – | – |
| *36* | | | | |
| *37* | **7(v): Subcomponents of Operational Expenditure (where known)** | | | |
| *38* | Energy efficiency and demand side management, reduction of energy losses | | – | – |
| *39* | Direct billing | | – | – |
| *40* | Research and development | | – | – |
| *41* | Insurance | | – | – |
| *42* | | | | |

*43* *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

*44* *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-Network Name* | |

## SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

*sch ref*

8 **8(i): Billed Quantities by Price Component**

9

10

11 **Billed quantities by price component**

| sch ref | Consumer group name or price category code | Consumer type or types (eg, residential, commercial etc.) | Standard or non-standard consumer group (specify) | Average no. of ICPs in disclosure year | Energy delivered to ICPs in disclosure year (MWh) | | Daily Fixed Charge | Daily Fixed Charge | Consumption | Monthly Fixed Charge | Demand (incl Excess Demand) | Capacity | Excess Reactive Power | Excess Reactive Power | Asset Utilisation | Transmission Pass Through | Eligible Discount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 | | | | | | **Price component** | Daily Fixed Charge | Daily Fixed Charge | Consumption | Monthly Fixed Charge | Demand (incl Excess Demand) | Capacity | Excess Reactive Power | Excess Reactive Power | Asset Utilisation | Transmission Pass Through | Eligible Discount |
| 13 | | | | | | **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)** | ICP Day | Fixture Day | kWh | ICP Month | kVA | kVA | kVArh | kVAr | Per ICP | Per ICP | Per ICP |
| 14 | | | | | | | | | | | | | | | | | |
| 15 | DM1 - Principal Res - Low User | Residential | Standard | 13,584 | 73,472 | | 2,822,309 | | 75,984,760 | | | | | | | | |
| 16 | User | Residential | Standard | 17,495 | 92,366 | | 8,412,690 | | 92,409,386 | | | | | | | | |
| 17 | DM3 - Non-Principal Residence | Residential | Standard | 2,188 | 5,940 | | 504,355 | | 5,922,935 | | | | | | | | |
| 18 | Residence | Residential | Standard | 2,318 | 8,843 | | 1,085,962 | | 8,889,031 | | | | | | | | |
| 19 | DM7 - Principal Res - Standard | Residential | Standard | 6,844 | 62,013 | | 1,633,190 | | 61,932,094 | | | | | | | | |
| 20 | Standard | Residential | Standard | 8,355 | 79,786 | | 3,938,502 | | 79,859,920 | | | | | | | | |
| 21 | ND1 - Up to 70kVA (100A or less) | General | Standard | 6,024 | 68,556 | | 1,626,838 | | 69,231,390 | | | | | | | | |
| 22 | or less) | General | Standard | 3,801 | 47,899 | | 1,708,554 | | 47,888,482 | | | | | | | | |
| 23 | Metering) | General | Standard | 245 | 16,649 | | 62,347 | | 16,804,283 | | | | | | | | |
| 24 | Metering) | General | Standard | 168 | 21,083 | | 86,542 | | 21,095,117 | | | | | | | | |
| 25 | ND5 - Irrigation and Pumps | General | Standard | 70 | 2,212 | | 24,751 | | 2,537,847 | | | | | | | | |
| 26 | ND6 - Unmetered 24 Hour | General | Standard | 195 | 289 | | 70,293 | | 289,000 | | | | | | | | |
| 27 | ND7 - Unmetered Public Lighting | General | Standard | 11 | 2,609 | | | 2,953,004 | | | | | | | | | |
| 28 | ND12 - Builders Supply | General | Standard | 569 | 589 | | 202,733 | | 508,345 | | | | | | | | |
| 29 | ToU | Large Commercial | Standard | 50 | 8,381 | | 18,322 | | 8,381,146 | | | | 3,175 | | | | |
| 30 | LC2 - Low Voltage Capacity Based | Large Commercial | Standard | 29 | 20,617 | | 10,541 | | | | 53,971 | 71,763 | 5,019 | | | | |
| 31 | Capacity | Large Commercial | Standard | 85 | 65,520 | | 30,530 | | | | 201,911 | 283,864 | 23,534 | | | | |
| 32 | Based | Large Commercial | Standard | 2 | 1,599 | | 730 | | | | 5,407 | 7,080 | 1,932 | | | | |
| 33 | IND - Individual Pricing | Asset Based | Non-standard | 7 | 463,845 | | | | 463,844,768 | | | | | 52,706 | 8 | 8 | |
| 34 | Discount (1 to 1,999 kWh) | All Consumers | Standard | | | | | | | | | | | | | | 8,002 |
| 35 | Discount (2,000+ kWh) | All Consumers | Standard | | | | | | | | | | | | | | 52,059 |
| 36 | *Add extra rows for additional consumer groups or price category codes as necessary* | | | | | | | | | | | | | | | | |
| 37 | | | **Standard consumer totals** | 62,033 | 578,424 | | 22,239,189 | 2,953,004 | 491,733,736 | – | 261,289 | 362,707 | 33,661 | – | – | – | 60,061 |
| 38 | | | **Non-standard consumer totals** | 7 | 463,845 | | – | – | 463,844,768 | – | – | – | – | 52,706 | 8 | 8 | – |
| 39 | | | **Total for all consumers** | 62,040 | 1,042,269 | | 22,239,189 | 2,953,004 | 955,578,504 | – | 261,289 | 362,707 | 33,661 | 52,706 | 8 | 8 | 60,061 |

*Add extra columns for additional billed quantities by price component as necessary*

40

41

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-Network Name* | |

## SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

42 **8(ii): Line Charge Revenues ($000) by Price Component**

| | Consumer group name or price category code | Consumer type or types (eg, residential, commercial etc.) | Standard or non-standard consumer group (specify) | Total line charge revenue in disclosure year | Notional revenue foregone from posted discounts (if applicable) | Total distribution line charge revenue | Total transmission line charge revenue (if available) |
|---|---|---|---|---|---|---|---|
| 48 | DM1 - Principal Res - Low User | Residential | Standard | $6,303 | | $6,303 | |
| 49 | User | Residential | Standard | $13,906 | | $13,906 | |
| 50 | DM3 - Non-Principal Residence | Residential | Standard | $963 | | $963 | |
| 51 | Residence | Residential | Standard | $2,165 | | $2,165 | |
| 52 | DM7 - Principal Res - Standard | Residential | Standard | $4,569 | | $4,569 | |
| 53 | Standard | Residential | Standard | $11,807 | | $11,807 | |
| 54 | ND1 - Up to 70kVA (100A or less) | General | Standard | $8,815 | | $8,815 | |
| 55 | or less) | General | Standard | $7,326 | | $7,326 | |
| 56 | Metering) | General | Standard | $2,011 | | $2,011 | |
| 57 | Metering) | General | Standard | $2,620 | | $2,620 | |
| 58 | ND5 - Irrigation and Pumps | General | Standard | $210 | | $210 | |
| 59 | ND6 - Unmetered 24 Hour | General | Standard | $228 | | $228 | |
| 60 | ND7 - Unmetered Public Lighting | General | Standard | $667 | | $667 | |
| 61 | ND12 - Builders Supply | General | Standard | $308 | | $308 | |
| 62 | ToU | Large Commercial | Standard | $1,101 | | $1,101 | |
| 63 | LC2 - Low Voltage Capacity Based | Large Commercial | Standard | $1,078 | | $1,078 | |
| 64 | Capacity | Large Commercial | Standard | $4,337 | | $4,337 | |
| 65 | Based | Large Commercial | Standard | $113 | | $113 | |
| 66 | IND - Individual Pricing | Asset Based | Non-standard | $8,402 | | $8,402 | |
| 67 | Discount (1 to 1,999 kWh) | All Consumers | Standard | ($440) | | ($440) | |
| 68 | Discount (2,000+ kWh) | All Consumers | Standard | ($11,245) | | ($11,245) | |
| 69 | *Add extra rows for additional consumer groups or price category codes as necessary* | | | | | | |
| 70 | | | **Standard consumer totals** | $56,843 | – | $56,843 | – |
| 71 | | | **Non-standard consumer totals** | $8,402 | – | $8,402 | – |
| 72 | | | **Total for all consumers** | $65,246 | – | $65,246 | – |

**Line charge revenues ($000) by price component**

| | **Price component** | Daily Fixed Charge | Daily Fixed Charge | Consumption | Monthly Fixed Charge | Demand (incl Excess Demand) | Capacity | Excess Reactive Power | Excess Reactive Power | Asset Utilisation | Transmission Pass Through | Eligible discount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 46 | **Rate (eg, $ per day, $ per kWh, etc.)** | $ per ICP per Day | $ Fixture per Day | $ per kWh | ICP Month | kVA | kVA | $ per Excess kVArh | kVAr | Asset Value | Coincident kW Demand | $ per Eligibiity |
| 48 | DM1 - Principal Res - Low User | $423 | | $5,880 | | | | | | | | |
| 49 | User | $1,262 | | $12,644 | | | | | | | | |
| 50 | DM3 - Non-Principal Residence | $656 | | $307 | | | | | | | | |
| 51 | Residence | $1,412 | | $754 | | | | | | | | |
| 52 | DM7 - Principal Res - Standard | $1,633 | | $2,936 | | | | | | | | |
| 53 | Standard | $3,938 | | $7,868 | | | | | | | | |
| 54 | ND1 - Up to 70kVA (100A or less) | $2,928 | | $5,887 | | | | | | | | |
| 55 | or less) | $3,075 | | $4,250 | | | | | | | | |
| 56 | Metering) | $262 | | $1,749 | | | | | | | | |
| 57 | Metering) | $363 | | $2,257 | | | | | | | | |
| 58 | ND5 - Irrigation and Pumps | $45 | | $165 | | | | | | | | |
| 59 | ND6 - Unmetered 24 Hour | $91 | | $137 | | | | | | | | |
| 60 | ND7 - Unmetered Public Lighting | | $667 | | | | | | | | | |
| 61 | ND12 - Builders Supply | $264 | | $45 | | | | | | | | |
| 62 | ToU | $77 | | $1,019 | | | | $5 | | | | |
| 63 | LC2 - Low Voltage Capacity Based | $44 | | | | $3 | $1,023 | $8 | | | | |
| 64 | Capacity | $128 | | | | $127 | $4,043 | $39 | | | | |
| 65 | Based | $3 | | | | $10 | $97 | $3 | | | | |
| 66 | IND - Individual Pricing | | | $78 | | | | | $86 | $2,775 | $5,463 | |
| 67 | Discount (1 to 1,999 kWh) | | | | | | | | | | | ($440) |
| 68 | Discount (2,000+ kWh) | | | | | | | | | | | ($11,245) |
| 70 | **Standard consumer totals** | $16,605 | $667 | $45,898 | – | $139 | $5,163 | $55 | – | – | – | ($11,685) |
| 71 | **Non-standard consumer totals** | – | – | $78 | – | – | – | – | $86 | $2,775 | $5,463 | – |
| 72 | **Total for all consumers** | $16,605 | $667 | $45,976 | – | $139 | $5,163 | $55 | $86 | $2,775 | $5,463 | ($11,685) |

*Add extra columns for additional line charge revenues by price component as necessary*

**Check** OK

74 **8(iii): Number of ICPs directly billed**

75 **Number of directly billed ICPs at year end**

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-network Name* | |

## SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

*sch ref*

| *8* | Voltage | Asset category | Asset class | Units | Items at start of year (quantity) | Items at end of year (quantity) | Net change | Data accuracy (1–4) |
|---|---|---|---|---|---|---|---|---|
| *9* | All | Overhead Line | Concrete poles / steel structure | No. | 53,419 | 53,560 | 141 | 2 |
| *10* | All | Overhead Line | Wood poles | No. | 1,210 | 1,167 | (43) | 2 |
| *11* | All | Overhead Line | Other pole types | No. | 48 | 49 | 1 | 2 |
| *12* | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | 297 | 296 | (0) | 3 |
| *13* | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | 28 | 28 | – | 3 |
| *14* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | 12 | 12 | 1 | 3 |
| *15* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Oil pressurised) | km | 8 | 8 | – | 4 |
| *16* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Gas pressurised) | km | – | | – | 4 |
| *17* | HV | Subtransmission Cable | Subtransmission UG up to 66kV (PILC) | km | 3 | 3 | – | 4 |
| *18* | HV | Subtransmission Cable | Subtransmission UG 110kV+ (XLPE) | km | 0 | 0 | – | 4 |
| *19* | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Oil pressurised) | km | – | | – | 4 |
| *20* | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Gas Pressurised) | km | – | | – | 4 |
| *21* | HV | Subtransmission Cable | Subtransmission UG 110kV+ (PILC) | km | – | | – | 4 |
| *22* | HV | Subtransmission Cable | Subtransmission submarine cable | km | 1 | 1 | – | 4 |
| *23* | HV | Zone substation Buildings | Zone substations up to 66kV | No. | 21 | 21 | – | 4 |
| *24* | HV | Zone substation Buildings | Zone substations 110kV+ | No. | 1 | 1 | – | 4 |
| *25* | HV | Zone substation switchgear | 50/66/110kV CB (Indoor) | No. | – | | – | 4 |
| *26* | HV | Zone substation switchgear | 50/66/110kV CB (Outdoor) | No. | 20 | 19 | (1) | 2 |
| *27* | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | 29 | 29 | – | 2 |
| *28* | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | 178 | 175 | (3) | 2 |
| *29* | HV | Zone substation switchgear | 33kV RMU | No. | 4 | 4 | – | 4 |
| *30* | HV | Zone substation switchgear | 22/33kV CB (Indoor) | No. | 35 | 37 | 2 | 4 |
| *31* | HV | Zone substation switchgear | 22/33kV CB (Outdoor) | No. | 60 | 59 | (1) | 4 |
| *32* | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (ground mounted) | No. | 154 | 157 | 3 | 4 |
| *33* | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | – | | – | 4 |
| *34* | HV | Zone Substation Transformer | Zone Substation Transformers | No. | 41 | 43 | 2 | 4 |
| *35* | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 3,500 | 3,506 | 6 | 2 |
| *36* | HV | Distribution Line | Distribution OH Aerial Cable Conductor | km | – | | – | 4 |
| *37* | HV | Distribution Line | SWER conductor | km | – | | – | 4 |
| *38* | HV | Distribution Cable | Distribution UG XLPE or PVC | km | 254 | 263 | 9 | 3 |
| *39* | HV | Distribution Cable | Distribution UG PILC | km | 39 | 39 | (1) | 2 |
| *40* | HV | Distribution Cable | Distribution Submarine Cable | km | 2 | 2 | – | 1 |
| *41* | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers | No. | 32 | 33 | 1 | 4 |
| *42* | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | – | | – | 4 |
| *43* | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | 8,498 | 8,555 | 57 | 2 |
| *44* | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | 15 | 16 | 1 | 2 |
| *45* | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | 219 | 232 | 13 | 4 |
| *46* | HV | Distribution Transformer | Pole Mounted Transformer | No. | 5,979 | 6,011 | 32 | 3 |
| *47* | HV | Distribution Transformer | Ground Mounted Transformer | No. | 1,480 | 1,517 | 37 | 3 |
| *48* | HV | Distribution Transformer | Voltage regulators | No. | 12 | 12 | – | 4 |
| *49* | HV | Distribution Substations | Ground Mounted Substation Housing | No. | 118 | 119 | 1 | 4 |
| *50* | LV | LV Line | LV OH Conductor | km | 1,182 | 1,182 | 0 | 2 |
| *51* | LV | LV Cable | LV UG Cable | km | 788 | 812 | 24 | 2 |
| *52* | LV | LV Street lighting | LV OH/UG Streetlight circuit | km | 406 | 410 | 3 | 2 |
| *53* | LV | Connections | OH/UG consumer service connections | No. | 61,522 | 62,537 | 1,015 | 3 |
| *54* | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | 343 | 359 | 16 | 2 |
| *55* | All | SCADA and communications | SCADA and communications equipment operating as a single system | Lot | 1 | 1 | – | 4 |
| *56* | All | Capacitor Banks | Capacitors including controls | No | 25 | 23 | (2) | 4 |
| *57* | All | Load Control | Centralised plant | Lot | 6 | 6 | – | 4 |
| *58* | All | Load Control | Relays | No | 39,225 | 39,227 | 2 | 3 |
| *59* | All | Civils | Cable Tunnels | km | – | – | – | |

| | |
|---|---|
| Company Name | Northpower Limited |
| For Year Ended | 31 March 2022 |
| Network / Sub-network Name | |

## SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

*sch ref*

8 **Disclosure Year (year ended)** 31 March 2022

**Number of assets at disclosure year end by installation date**

| sch ref | Voltage | Asset category | Asset class | Units | pre-1940 | 1940–1949 | 1950–1959 | 1960–1969 | 1970–1979 | 1980–1989 | 1990–1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | No. with age unknown | Items at end of year | No. with default dates | Data accuracy (1–4) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Voltage | Asset category | Asset class | Units | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 10 | All | Overhead Line | Concrete poles / steel structure | No. | 150 | 152 | 1,538 | 8,057 | 13,230 | 9,636 | 7,799 | 622 | 506 | 682 | 681 | 847 | 792 | 658 | 578 | 610 | 725 | 724 | 667 | 704 | 592 | 605 | 579 | 523 | 390 | 326 | 355 | 380 | 365 | 87 | | | | | 53,560 | | [Select one] |
| 11 | All | Overhead Line | Wood poles | No. | 1 | | 10 | 63 | 147 | 450 | 252 | 16 | 22 | 24 | 38 | 53 | 32 | 23 | 5 | 8 | 3 | 3 | 4 | | 3 | 2 | 2 | 2 | | 2 | 2 | | | | | | | | 1,167 | | [Select one] |
| 12 | All | Overhead Line | Other pole types | No. | | | 2 | 5 | 13 | 20 | 4 | | | 2 | | 2 | | | 1 | | | | | | | | | | | | | | | | | | | | 49 | | [Select one] |
| 13 | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | | | 71 | 104 | 28 | 38 | 46 | 4 | 0 | 0 | 1 | 0 | | | 0 | 0 | 0 | 0 | | 1 | 0 | | | | | | 1 | 2 | | 0 | | | | | 296 | | [Select one] |
| 14 | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | | | | | 28 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 28 | | [Select one] |
| 15 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | | | | | | 1 | 0 | 1 | 3 | 0 | 0 | | 0 | 0 | 0 | | 3 | 0 | | 0 | | 2 | 0 | | | | 0 | 0 | 1 | 0 | | | | | 12 | | [Select one] |
| 16 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Oil pressurised) | km | | | | 5 | 3 | 0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 8 | | [Select one] |
| 17 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Gas pressurised) | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 18 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (PILC) | km | | | | | | 3 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 3 | | [Select one] |
| 19 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (XLPE) | km | | | | | | | 0 | | | | | | | | | | | | | | | | 0 | | | | | | | | | | | | 0 | | [Select one] |
| 20 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Oil pressurised) | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 21 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Gas Pressurised) | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 22 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (PILC) | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 23 | HV | Subtransmission Cable | Subtransmission submarine cable | km | | | | | | | 1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1 | | [Select one] |
| 24 | HV | Zone substation Buildings | Zone substations up to 66kV | No. | 1 | | 3 | 7 | 1 | 4 | 1 | 1 | | | | | | | 1 | 1 | | | | | | | | | | | | | 1 | | | | | | 21 | | [Select one] |
| 25 | HV | Zone substation Buildings | Zone substations 110kV+ | No. | | | | | | 1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1 | | [Select one] |
| 26 | HV | Zone substation switchgear | 50/66/110kV CB (Indoor) | No. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 27 | HV | Zone substation switchgear | 50/66/110kV CB (Outdoor) | No. | 1 | 2 | 6 | 2 | | | 3 | 3 | | 2 | | | | | | | | | | | | | | | | | | | | | | | | | 19 | | [Select one] |
| 28 | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | | | | | | | | | | | | | | 4 | | 24 | 1 | | | | | | | | | | | | | | | | | | 29 | | [Select one] |
| 29 | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | | | 14 | 63 | 10 | 11 | 2 | 2 | | 4 | 5 | 1 | 26 | 3 | 1 | 8 | 5 | 2 | 1 | 4 | 2 | | | | 5 | | 6 | | | | | | | | 175 | | [Select one] |
| 30 | HV | Zone substation switchgear | 33kV RMU | No. | | | | | | | | 2 | 2 | | | | | | | | | | | | | | | | | | | | | | | | | | 4 | | [Select one] |
| 31 | HV | Zone substation switchgear | 22/33kV CB (Indoor) | No. | | | | | | 18 | 1 | | 1 | 1 | | | | 1 | | 3 | 2 | | | | 1 | 1 | | | | | 5 | 3 | | | | | | | 37 | | [Select one] |
| 32 | HV | Zone substation switchgear | 22/33kV CB (Outdoor) | No. | | | | | | 5 | 23 | 6 | | | | 5 | 1 | 3 | 1 | | 2 | | | 2 | | | 5 | 1 | 4 | | | | 1 | | | | | | 59 | | [Select one] |
| 33 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (ground mounted) | No. | | | | 10 | 13 | 20 | 1 | | 5 | | 4 | | | 9 | 31 | | 17 | 12 | | | 1 | | | | | | 17 | 11 | 6 | | | | | | 157 | | [Select one] |
| 34 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 35 | HV | Zone Substation Transformer | Zone Substation Transformers | No. | | | 3 | 12 | 6 | 4 | | | 1 | 2 | 1 | | 2 | | | | 2 | | | | | 2 | | | 1 | 2 | 2 | 2 | 1 | | | | | | 43 | | [Select one] |
| 36 | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 13 | 19 | 83 | 553 | 693 | 682 | 585 | 73 | 30 | 47 | 31 | 65 | 33 | 21 | 21 | 19 | 19 | 23 | 40 | 67 | 79 | 26 | 42 | 34 | 36 | 38 | 61 | 35 | 31 | 5 | | | | | 3,506 | | [Select one] |
| 37 | HV | Distribution Line | Distribution OH Aerial Cable Conductor | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 38 | HV | Distribution Line | SWER conductor | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 39 | HV | Distribution Cable | Distribution UG XLPE or PVC | km | | | | 1 | 0 | 10 | 30 | 7 | 7 | 12 | 9 | 15 | 24 | 27 | 21 | 8 | 12 | 4 | 3 | 4 | 9 | 5 | 6 | 6 | 6 | 7 | 10 | 9 | 10 | 1 | | | | | 263 | | [Select one] |
| 40 | HV | Distribution Cable | Distribution UG PILC | km | | | | 5 | 9 | 14 | 8 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | | 0 | | 0 | 0 | 0 | | | | | | | | | | | | | | | 39 | | [Select one] |
| 41 | HV | Distribution Cable | Distribution Submarine Cable | km | | | | | 2 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 2 | | [Select one] |
| 42 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers | No. | | | | | | | | 2 | 1 | | | 1 | 8 | | 1 | 2 | 2 | 1 | 1 | 3 | 2 | 2 | 2 | | 1 | 1 | | 2 | 1 | | | | | | 33 | | [Select one] |
| 43 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |
| 44 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | 6 | 8 | 9 | 137 | 244 | 571 | 1,091 | 137 | 129 | 149 | 153 | 206 | 217 | 223 | 205 | 368 | 533 | 355 | 487 | 391 | 399 | 367 | 405 | 292 | 313 | 266 | 282 | 256 | 291 | 65 | | | | | 8,555 | | [Select one] |
| 45 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | | | | | 4 | 8 | | | | | | | | | | | | | | | | | | | | 2 | 1 | 1 | | | | | | | 16 | | [Select one] |
| 46 | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | | | | | 3 | 8 | 16 | 2 | 4 | 2 | 2 | 5 | 31 | 26 | 6 | 9 | 22 | 4 | 5 | 5 | 6 | 7 | 8 | 8 | 11 | 8 | 11 | 11 | 11 | 1 | | | | | 232 | | [Select one] |
| 47 | HV | Distribution Transformer | Pole Mounted Transformer | No. | 77 | 120 | 109 | 526 | 434 | 419 | 1,108 | 167 | 130 | 151 | 130 | 168 | 158 | 161 | 202 | 122 | 145 | 47 | 138 | 91 | 138 | 225 | 148 | 114 | 170 | 152 | 195 | 151 | 109 | 6 | | | | | 6,011 | | [Select one] |
| 48 | HV | Distribution Transformer | Ground Mounted Transformer | No. | 3 | 3 | 14 | 161 | 163 | 156 | 138 | 35 | 35 | 40 | 28 | 56 | 82 | 85 | 69 | 25 | 36 | 48 | 6 | 1 | 14 | 34 | 47 | 36 | 43 | 32 | 44 | 39 | 44 | | | | | | 1,517 | | [Select one] |
| 49 | HV | Distribution Transformer | Voltage regulators | No. | | | | | 2 | | 2 | | | | | 3 | | | | | | | | | | | 3 | | | | 2 | | | | | | | | 12 | | [Select one] |
| 50 | HV | Distribution Substations | Ground Mounted Substation Housing | No. | | | 1 | 13 | 21 | 23 | 31 | 5 | 1 | 7 | 1 | 1 | | | 1 | 4 | 2 | 1 | 1 | 2 | 1 | | | | | 2 | 1 | | | | | | | | 119 | | [Select one] |
| 51 | LV | LV Line | LV OH Conductor | km | 1 | 1 | 20 | 151 | 171 | 492 | 171 | 10 | 8 | 10 | 22 | 22 | 19 | 14 | 6 | 5 | 7 | 5 | 5 | 3 | 3 | 3 | 4 | 3 | 3 | 4 | 5 | 8 | 4 | 2 | | | | | 1,182 | | [Select one] |
| 52 | LV | LV Cable | LV UG Cable | km | 0 | | 0 | 24 | 52 | 76 | 86 | 19 | 21 | 28 | 36 | 48 | 52 | 49 | 47 | 26 | 29 | 16 | 7 | 6 | 17 | 8 | 15 | 24 | 25 | 29 | 25 | 21 | 21 | 6 | | | | | 812 | | [Select one] |
| 53 | LV | LV Street lighting | LV OH/UG Streetlight circuit | km | | | 2 | 47 | 149 | 40 | 52 | 2 | 4 | 3 | 4 | 8 | 10 | 12 | 11 | 6 | 12 | 1 | 3 | 1 | 3 | 6 | 4 | 3 | 6 | 7 | 4 | 4 | 5 | 0 | | | | | 410 | | [Select one] |
| 54 | LV | Connections | OH/UG consumer service connections | No. | | | | | | | 9,400 | 33,699 | 823 | 904 | 1,109 | 1,128 | 1,181 | 1,116 | 1,061 | 854 | 779 | 745 | 595 | 633 | 633 | 620 | 835 | 1,056 | 1,135 | 1,042 | 976 | 914 | 1,072 | 227 | | | | | 62,537 | | [Select one] |
| 55 | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | | | | | 8 | 21 | 57 | 7 | 6 | 5 | | 6 | 20 | 13 | 29 | 25 | 16 | 30 | 3 | 7 | 1 | 4 | 2 | 25 | | 18 | 27 | 20 | 8 | 1 | | | | | 359 | | [Select one] |
| 56 | All | SCADA and communications | SCADA and communications equipment operating as a single sys | Lot | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1 | | | | | | | 1 | | [Select one] |
| 57 | All | Capacitor Banks | Capacitors including controls | No | | | | | | | 5 | | | | | | 2 | | | 1 | 5 | 5 | | 3 | | | | 1 | | | | | | 1 | | | | | 23 | | [Select one] |
| 58 | All | Load Control | Centralised plant | Lot | | | | | | 2 | | | | | | 2 | | | 1 | | | 1 | | | | | | | | | | | | | | | | | 6 | | [Select one] |
| 59 | All | Load Control | Relays | No | | | | | | 5,694 | 7,256 | 1,103 | 843 | 857 | 3,310 | 5,649 | 1,176 | 853 | 1,112 | 1,221 | 743 | 906 | 605 | 519 | 1,013 | 971 | 1,422 | 853 | 873 | 910 | 786 | 531 | 19 | 2 | | | | | 39,227 | | [Select one] |
| 60 | All | Civils | Cable Tunnels | km | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | – | | [Select one] |

| | |
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| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-network Name* | |

## SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

*sch ref*

| | | | | |
|---|---|---|---|---|
| *9* | | | | |
| *10* | **Circuit length by operating voltage (at year end)** | **Overhead (km)** | **Underground (km)** | **Total circuit length (km)** |
| *11* | > 66kV | 28 | 0 | 28 |
| *12* | 50kV & 66kV | 75 | | 75 |
| *13* | 33kV | 221 | 24 | 245 |
| *14* | SWER (all SWER voltages) | | | – |
| *15* | 22kV (other than SWER) | | | – |
| *16* | 6.6kV to 11kV (inclusive—other than SWER) | 3,506 | 303 | 3,809 |
| *17* | Low voltage (< 1kV) | 1,182 | 812 | 1,994 |
| *18* | **Total circuit length (for supply)** | 5,013 | 1,139 | 6,151 |
| *19* | | | | |
| *20* | Dedicated street lighting circuit length (km) | 174 | 236 | 410 |
| *21* | Circuit in sensitive areas (conservation areas, iwi territory etc) (km) | | | 120 |
| *22* | | | | |
| *23* | **Overhead circuit length by terrain (at year end)** | **Circuit length (km)** | **(% of total overhead length)** | |
| *24* | Urban | 571 | 11% | |
| *25* | Rural | 4,442 | 89% | |
| *26* | Remote only | | – | |
| *27* | Rugged only | | – | |
| *28* | Remote and rugged | | – | |
| *29* | Unallocated overhead lines | | – | |
| *30* | **Total overhead length** | 5,013 | 100% | |
| *31* | | | | |
| *32* | | **Circuit length (km)** | **(% of total circuit length)** | |
| *33* | Length of circuit within 10km of coastline or geothermal areas (where known) | 3,414 | 56% | |
| *34* | | **Circuit length (km)** | **(% of total overhead length)** | |
| *35* | Overhead circuit requiring vegetation management | 5,013 | 100% | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |

## SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

This schedule requires information concerning embedded networks owned by an EDB that are embedded in another EDB's network or in another embedded network.

*sch ref*

| | Location * | Number of ICPs served | Line charge revenue ($000) |
|---|---|---|---|
| *8* | | | |
| *9* | | | |
| *10* | | | |
| *11* | | | |
| *12* | | | |
| *13* | | | |
| *14* | | | |
| *15* | | | |
| *16* | | | |
| *17* | | | |
| *18* | | | |
| *19* | | | |
| *20* | | | |
| *21* | | | |
| *22* | | | |
| *23* | | | |
| *24* | | | |
| *25* | | | |

*26* ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-network Name* | |

# SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

| *sch ref* | | | | |
|---|---|---|---|---|
| 8 | | **9e(i): Consumer Connections** | | |
| 9 | | *Number of ICPs connected in year by consumer type* | | |
| 10 | | *Consumer types defined by EDB** | **Number of connections (ICPs)** | |
| 11 | | Mass Market New ICPs | 1,093 | |
| 12 | | Large Commercial and Industrial (ND9) New ICPs | 3 | |
| 13 | | Very Large Industrial New ICPs | – | |
| 14 | | | | |
| 15 | | | | |
| 16 | | ** include additional rows if needed* | | |
| 17 | | **Connections total** | 1,096 | |
| 18 | | | | |
| 19 | | **Distributed generation** | | |
| 20 | | Number of connections made in year | 287 | **connections** |
| 21 | | Capacity of distributed generation installed in year | 2.40 | **MVA** |
| 22 | | **9e(ii): System Demand** | | |
| 23 | | | | |
| 24 | | | | |
| 25 | | **Maximum coincident system demand** | **Demand at time of maximum coincident demand (MW)** | |
| 26 | | GXP demand | 178 | |
| 27 | *plus* | Distributed generation output at HV and above | 4 | |
| 28 | | **Maximum coincident system demand** | 182 | |
| 29 | *less* | Net transfers to (from) other EDBs at HV and above | | |
| 30 | | **Demand on system for supply to consumers' connection points** | 182 | |
| 31 | | **Electricity volumes carried** | **Energy (GWh)** | |
| 32 | | Electricity supplied from GXPs | 1,071 | |
| 33 | *less* | Electricity exports to GXPs | – | |
| 34 | *plus* | Electricity supplied from distributed generation | 20 | |
| 35 | *less* | Net electricity supplied to (from) other EDBs | – | |
| 36 | | **Electricity entering system for supply to consumers' connection points** | 1,091 | |
| 37 | *less* | Total energy delivered to ICPs | 1,042 | |
| 38 | | **Electricity losses (loss ratio)** | 49 | 4.5% |
| 39 | | | | |
| 40 | | **Load factor** | 0.68 | |
| 41 | | **9e(iii): Transformer Capacity** | | |
| 42 | | | **(MVA)** | |
| 43 | | Distribution transformer capacity (EDB owned) | 588 | |
| 44 | | Distribution transformer capacity (Non-EDB owned, estimated) | 6 | |
| 45 | | **Total distribution transformer capacity** | 594 | |
| 46 | | | | |
| 47 | | **Zone substation transformer capacity** | 354 | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-network Name* | |

## SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

| *sch ref* | | | |
|---|---|---|---|
| *8* | **10(i): Interruptions** | | |
| *9* | **Interruptions by class** | **Number of interruptions** | |
| *10* | Class A (planned interruptions by Transpower) | | |
| *11* | Class B (planned interruptions on the network) | 427 | |
| *12* | Class C (unplanned interruptions on the network) | 471 | |
| *13* | Class D (unplanned interruptions by Transpower) | 3 | |
| *14* | Class E (unplanned interruptions of EDB owned generation) | | |
| *15* | Class F (unplanned interruptions of generation owned by others) | | |
| *16* | Class G (unplanned interruptions caused by another disclosing entity) | | |
| *17* | Class H (planned interruptions caused by another disclosing entity) | | |
| *18* | Class I (interruptions caused by parties not included above) | | |
| *19* | **Total** | 901 | |
| *20* | | | |
| *21* | **Interruption restoration** | **≤3Hrs** | **>3hrs** |
| *22* | Class C interruptions restored within | 330 | 141 |
| *23* | | | |
| *24* | **SAIFI and SAIDI by class** | **SAIFI** | **SAIDI** |
| *25* | Class A (planned interruptions by Transpower) | | |
| *26* | Class B (planned interruptions on the network) | 0.48 | 117.2 |
| *27* | Class C (unplanned interruptions on the network) | 4.06 | 258.5 |
| *28* | Class D (unplanned interruptions by Transpower) | 0.18 | 3.5 |
| *29* | Class E (unplanned interruptions of EDB owned generation) | | |
| *30* | Class F (unplanned interruptions of generation owned by others) | | |
| *31* | Class G (unplanned interruptions caused by another disclosing entity) | | |
| *32* | Class H (planned interruptions caused by another disclosing entity) | | |
| *33* | Class I (interruptions caused by parties not included above) | | |
| *34* | **Total** | 4.72 | 379.3 |
| *35* | | | |
| *36* | **Normalised SAIFI and SAIDI** | **Normalised SAIFI** | **Normalised SAIDI** |
| *37* | Classes B & C (interruptions on the network) | 4.34 | 278.6 |
| *38* | | | |

| | |
|---|---|
| *Company Name* | **Northpower Limited** |
| *For Year Ended* | **31 March 2022** |
| *Network / Sub-network Name* | |

## SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

### 10(ii): Class C Interruptions and Duration by Cause

| Cause | SAIFI | SAIDI |
|---|---|---|
| Lightning | 0.24 | 3.1 |
| Vegetation | 0.36 | 25.0 |
| Adverse weather | 0.57 | 84.7 |
| Adverse environment | 0.00 | 0.0 |
| Third party interference | 0.39 | 30.0 |
| Wildlife | 0.39 | 15.1 |
| Human error | 0.01 | 0.1 |
| Defective equipment | 1.32 | 87.7 |
| Cause unknown | 0.80 | 12.9 |

### 10(iii): Class B Interruptions and Duration by Main Equipment Involved

| Main equipment involved | SAIFI | SAIDI |
|---|---|---|
| Subtransmission lines | 0.01 | 1.8 |
| Subtransmission cables | | |
| Subtransmission other | | |
| Distribution lines (excluding LV) | 0.43 | 104.7 |
| Distribution cables (excluding LV) | 0.05 | 10.7 |
| Distribution other (excluding LV) | | |

### 10(iv): Class C Interruptions and Duration by Main Equipment Involved

| Main equipment involved | SAIFI | SAIDI |
|---|---|---|
| Subtransmission lines | 1.46 | 68.6 |
| Subtransmission cables | | |
| Subtransmission other | | |
| Distribution lines (excluding LV) | 2.55 | 185.9 |
| Distribution cables (excluding LV) | 0.05 | 4.1 |
| Distribution other (excluding LV) | | |

### 10(v): Fault Rate

| Main equipment involved | Number of Faults | Circuit length (km) | Fault rate (faults per 100km) |
|---|---|---|---|
| Subtransmission lines | 26 | 324 | 8.01 |
| Subtransmission cables | | 24 | – |
| Subtransmission other | | | |
| Distribution lines (excluding LV) | 443 | 3,506 | 12.64 |
| Distribution cables (excluding LV) | 12 | 303 | 3.96 |
| Distribution other (excluding LV) | | | |
| **Total** | 481 | | |

| | |
|---|---|
| Company Name | Northpower Limited |
| For Year Ended | 31 March 2022 |

## Schedule 14 Mandatory Explanatory Notes

*(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination)*

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

*Return on Investment (Schedule 2)*

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

**Box 1: Explanatory comment on return on investment**

The calculated post tax ROI and vanilla ROI for disclosure year were 8.46% and 8.76% respectively. This compares to 2.96% and 3.29% for the previous year. The significant factors driving the increase in ROI is the much higher CPI impact on the RAB revaluation ($20.6m vs $4.2m). The revaluation is based on the closing CPI, which for FY22 was 6.93% and for FY21 was 1.53%.

*Regulatory Profit (Schedule 3)*

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

   5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3

   5.2 information on reclassified items in accordance with subclause 2.7.1(2).

**Box 2: Explanatory comment on regulatory profit**

Other regulatory income of $770k relates to value added work on charged to customers.

*Merger and acquisition expenses (3(iv) of Schedule 3)*

6. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below-

   6.1 information on reclassified items in accordance with subclause 2.7.1(2)

   6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

| **Box 3: Explanatory comment on merger and acquisition expenditure** |
|---|
| Not applicable – there were no incurred merger and acquisition expenditure during the disclosure year. |

*Value of the Regulatory Asset Base (Schedule 4)*

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

| **Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)** |
|---|
| • The RAB roll-forward in Schedule 4 is determined in accordance with the IM requirements.<br>• There were no reclassifications made.<br>• Disposed assets of $449k were mainly non Network assets impacted by a change in the treatment of Software as a Service related costs. Previously, configuration costs associated with software as a service systems were included in RAB assets (consistent with the treatment adopted for financial reporting purposes). However, during FY22 there was a change to the financial reporting treatment and many of these costs are now expensed as incurred. This revised treatment has been applied to the RAB.<br>• Shared assets in the RAB have been allocated with the application of the ABAA approach for this disclosure year. Refer box 8 for details. |

*Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)*

8. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

   8.1 Income not included in regulatory profit / (loss) before tax but taxable;

   8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   8.3 Income included in regulatory profit / (loss) before tax but not taxable;

   8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

**Box 5: Regulatory tax allowance: permanent differences**
$12k expenditure or loss in regulatory profit before tax but not tax deductible relates to non deductible entertainment expenditure.

*Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)*

9. In the box below, provide descriptions and workings of material items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

**Box 6: Tax effect of other temporary differences (current disclosure year)**
The tax effect of temporary differences of $8k represents tax on the movement between FY21 and FY22 in the following provisions:

- Holiday leave provisions;
- Long service leave provisions;
- Bonus accrual;
- Doubtful debt provision;
- Cost of financing

*Cost allocation (Schedule 5d)*

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

**Box 7: Cost allocation**

Cost allocations were calculated using the ABAA methodology as per Part 2.1 of the IM determination for business support.

Business support costs not directly attributable has increased by $117k from FY21. This was large driven by:

- A decrease in finance costs due to a movement in the allocators, which resulted in a lower proportion allocated to the EDB

- An increase in Executive/Strategy costs due to cost increases in this area

- An increase in IT costs due to cost increases in implementation of new software as a service systems.

The allocator applied to finance costs has been updated from the proportion of gross margin percentages to gross margin amount. The updated allocator provides a more reasonable reflection of the Distribution Business share of these costs. All other allocation categories are consistent with the prior year, and are outlined below:

- Human resource costs allocated using headcount as causal allocator.
- Information technology costs allocated using the weighted average of devices as a causal allocator.
- Finance costs allocated using gross margin as a proxy allocator.
- Facilities costs allocated using floor space as a causal allocator.
- Corporate costs allocated using non-current assets as a proxy allocator.
- HSQE is allocated using headcount as a causal allocator.

*Asset allocation (Schedule 5e)*

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

**Box 8: Commentary on asset allocation**

Asset allocations were calculated using the ABAA methodology as per Part 2.1 of the IM determination. A summary of RAB assets that were allocated are as follows:

- Sub transmission line, distribution and LV line assets – Shared pole assets used for fibre and network assets (proxy allocator).
- Distribution and LV cables – 100% of CBD ducts and civils exclusively used for the Fibre business.
- Other network assets – Backhaul fibre assets shared between the Fibre and Network business (causal allocator).
- Land and buildings – Estimated area shared between regulated network and non-network businesses (proxy allocator).

The method of asset allocations is consistent with the prior year. No items were reclassified.

*Capital Expenditure for the Disclosure Year (Schedule 6a)*

12. In the box below, comment on expenditure on assets for the disclosure year, as disclosed in Schedule 6a. This comment must include-

    12.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

    12.2 information on reclassified items in accordance with subclause 2.7.1(2).

**Box 9: Explanation of capital expenditure for the disclosure year**

The largest component of capex in FY22 was asset replacement, followed by consumer connections. This trend is consistent with FY19, FY20 and FY21.
All capex projects or programmes above a $50k threshold have been described in schedule 6a, and where possible, we have aggregated projects below this threshold.
No items were reclassified.

*Operational Expenditure for the Disclosure Year (Schedule 6b)*

13. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-

    13.1 Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;

    13.2 Information on reclassified items in accordance with subclause 2.7.1(2);

    13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

**Box 10: Explanation of operational expenditure for the disclosure year**

Asset replacement and renewal operating expenditure relates to work done to make good on defects identified during scheduled preventative maintenance inspections.

- There are no reclassified items to report.
- There is no material atypical expenditure included in the operational expenditure.
- Operational expenditure has increased across all categories, other than asset replacement and renewal and vegetation management, in response to asset condition and risk monitoring. The largest increase in expenditure was:
    - Service interruptions and emergencies
- Business support – please refer Box 7

*Variance between forecast and actual expenditure (Schedule 7)*

14. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

**Box 11: Explanatory comment on variance in actual to forecast expenditure**

Asset expenditure was overall 3% lower than the target expenditure. Consumer connection expenditure was significantly higher than forecast and this was driven by an increased number of large subdivisions in the area. This was offset by lower spend on Non Network assets where Covid 19 impacted progress and asset replacement and renewal.

- Network Opex was 2% lower than target mainly from vegetation management and asset replacement and renewal.

- Non-network Opex was 7% higher than target with both system operations and business support costs higher than forecast.

*Information relating to revenues and quantities for the disclosure year*

15. In the box below provide-

    15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

    15.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

| **Box 12: Explanatory comment relating to revenue for the disclosure year** |
|---|
| Target revenue disclosed before the start of the year was 6% lower than the total billed line charge revenue for the disclosure year. There was a favourable variance related to Covid 19 impacts and higher consumption per ICP.<br><br>The FY22 target revenue of $61.5m is included post discount whereas the FY21 target revenue was included in the FY21 disclosures pre discount at $71.9m. The FY21 target revenue post discount was $61.6m. |

*Network Reliability for the Disclosure Year (Schedule 10)*

16. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

| **Box 13: Commentary on network reliability for the disclosure year** |
|---|
| The results for FY22 network reliability and performance results were relatively stable for the first three quarter of the financial year but sustained adverse weather during the last quarter which saw these results become adverse. This is illustrated by the number of adverse weather-related days in FY22 of 55 compared to an average for FY16 to FY21 of 32.<br><br>Targets for unplanned SAIDI, unplanned SAIFI and faults per 100km were not met in FY22 due to adverse weather events with vegetation being the major cause of faults during these events. These events included a storm in June (22 HV events), Cyclone Dovi in February (56 HV events (raw SAIDI impact 75.2)) and March lighting storm (28 HV events). Underlying network health is strong, with year on year reductions over the last three years in outages caused by defective equipment, reflecting the results of proactive corrective maintenance regimes. We continue to focus on ways to make the network more resilient to adverse weather events, as these are expected to become more common.<br><br>Planned SAIDI remain at similar levels to FY21 with the continuing focus on asset renewal across the network to ensure resilience and reliability. |

*Insurance cover*

17. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

    17.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

    17.2 In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

**Box 14: Explanation of insurance cover**

Significant assets located in one place (e.g. zone substations, control room, other buildings) are insured under a comprehensive replacement insurance policy. Assets that are spread over a large area (e.g. lines, cables and distribution transformers) are uninsured.

*Amendments to previously disclosed information*

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    18.1 a description of each error; and

    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

**Box 15: Disclosure of amendment to previously disclosed information**

No amendments to previously disclosed information.

Company Name Northpower Limited

For Year Ended 31 March 2022

## Schedule 15 Voluntary Explanatory Notes

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)*

1. This schedule enables EDBs to provide, should they wish to-

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;

    1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

**Provide additional explanatory comment in the box below.Box 1: Voluntary explanatory comment on disclosed information**

**S8. Billed Quantities + Revenues – price components**

Volume information for price category codes disclosed in schedule 8 is received from retailers at the more detailed price component code level. Some price component codes are used across multiple price category codes and in these instances it is not possible to determine the volume and revenues for each price category code. The volumes and revenue for the price component codes that are shared across multiple price category codes have been treated as being derived from the price category code which is likely to consume the largest proportion.

**S8. Billed Quantities + Revenues – ND7 consumption**

Excludes consumption by private streetlights as we do not hold this information because we invoice on a wattage basis rather than consumption. Consumers provide voluntary consumption data for public streetlights only. This is consistent with prior years and does not have a significant impact on the disclosures in schedule 8.

**S9b. Asset Age Profile**

The asset age profile data has been presented by calendar year, which is consistent with prior years. This treatment has been adopted because we do not hold information on the month of installation for historic assets and therefore are not able to align the data to 31 March year ends.

**S10. Report on Network Reliability**

Reliability measures have been calculated on a consistent basis with previous years, including the treatment of successive interruptions. During the interruption to supply, some customers may be temporarily resorted for a short period due to switching operations carried out in the course of locating a fault (e.g. opening a switch, reclosing a circuit breaker to identify which section has the fault, and repeating this along the circuit until the fault is identified). Northpower treats this activity as one interruption. This is because, until the fault has been located and addressed, supply has not properly been restored along the HV.

# NORTHPOWER NETWORK YEAR TO 31 MARCH 2022 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (EDID) FOR RELATED PARTY TRANSACTIONS

## Table of Contents

Northpower

# Summary of Northpower Network's Related Party Transactions

**(Clause 2.3.8 of EDID requirements)**

| Related Party | Nature of Relationship | Principal Activity of Related Party | FY22 Expenditure with Related Party |
|---|---|---|---|
| Northpower Contracting Division | Both Northpower Network and Contracting division are part of Northpower Limited | The Contracting division provides maintenance and construction services for the electricity network. | Capital expenditure $17.0m<br>Operating expenditure (maintenance) $11.3m |
| Northpower Fibre Limited | Northpower Limited is a shareholder of Northpower Fibre Limited | Northpower Fibre Limited owns and operates an ultra-fast broadband network in the Whangarei area. | Operating expenditure (leased fibre scada circuit for communications) $24k |
| Busck Prestressed Concrete Limited | Mr Paul Yovich is a Trustee of Northpower Electric Power Trust, the Shareholder of Northpower Limited. Mr Yovich is also a Trustee of a Shareholder of Busck Prestressed Concrete Limited. | Supplier of concrete products to the network, mainly poles<br><br>(Note: the majority of purchases from this supplier are made by Northpower Contracting division. This related party disclosure is for purchases made directly by Northpower Network.) | Capex<br>$0k |
| Electricity Engineers' Association (EEA) | Ms Josie Boyd is the GM of Northpower Network and an Executive Committee Member of the Electricity Engineers' Association. | Professional engineers employed by Northpower Network are members of the EEA and purchase products from EEA. | Operating expenditure $20k |

Northpower

# Summary of Northpower Network's Policy in Respect of Procurement of Assets or Goods or Services from any Related Party

**(Clause 2.3.10 of EDID requirements)**

## Purpose

This is a summary of the policy that outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

## Introduction

This document outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

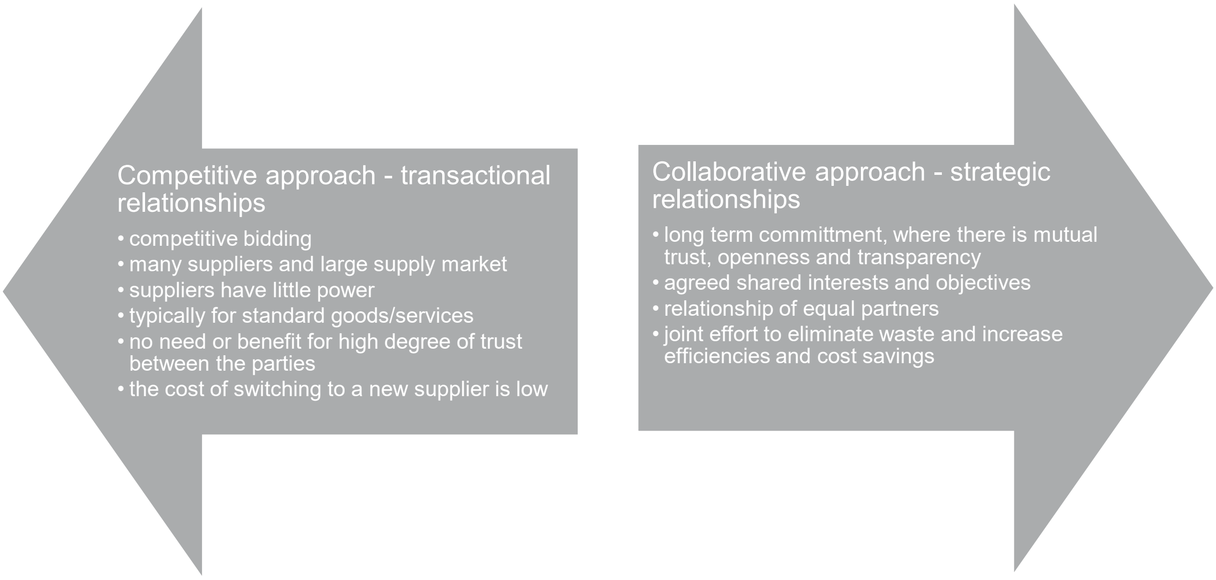
## Procurement Objectives

The following objectives will inform Network's decision around the procurement of goods and services:

1. Ensuring that the services delivered meet the requirements and expectations of the consumers of Whangarei and Kaipara.
2. A delivery model that is cost effective and delivers efficiencies for the long-term benefit of consumers.
3. Achieving a high performing HSQE culture across all areas of its business, including staff and contractors.
4. The delivery of works programmes in accordance with Northpower's asset management strategies, including the ability to access resources to meet peak workloads.
5. Achieving innovation and continuous improvement in the areas identified above.

The choice around suppliers and procurement models, including transactions with related parties, will depend on the existing market for the specific goods or services, the strategic importance of the services, and the long-term needs of Network and its consumers.

Goods or services with characteristics that support a transactional relationship are likely to be subject to market contestability. In contrast, strategic supplier relationships are more likely to be based on a collaborative approach, underpinned by long-term relationships.




Where goods or services are not acquired through market contestability, Northpower will ensure that transactions are valued as if they were an arm's-length transaction.

## Valuation of Transactions

Transactions between Network and its related parties will be conducted and valued as if it were an arm's-length transaction.

To meet these requirements, the following principles will be applied to all transactions with a related party who is providing goods or services to Network:

1. The value of a good or service acquired by Network must be given a value not greater than if that transaction had the terms of an arm's-length transaction;
2. The value of an asset or good or service sold or supplied to Network must be given a value not less than if that transaction had the terms of an arm's-length transaction;
3. Network will use an objective and independent measure in determining the terms of an arm's-length transaction for the purpose of principles 1 and 2 above.

For the purpose of principle 1, where a good or service is acquired from a third party and then on-sold to a related entity, the value of the subsequent transfer between related entities must reflect the amount charged by the third party.

## Objective & Independent Measures of Value

Northpower will ensure that transactions with its related parties are valued on arm's-length terms by utilising independent and objective measures to establish that a related party transaction value is consistent with the value that would have otherwise been charged by an unrelated party commissioned to do the same work.

Methods used may include any or all of the following depending on the nature of the proposed transaction, the information reasonably available and what is practicable in the circumstances given the market for the relevant services.

- Conducting a tendering process for the goods or services.
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by the related party to its other customers.
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by similar external providers.
- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or services.
- Engaging an expert to undertake an independent valuation to determine market value of the goods or service.

## Success Measures (Outcomes)

Successful implementation of this Network Policy will achieve the following outcomes:

- The Network Policy principles and objectives are met.
- Related party transactions are valued based on objective customer transactions.
- Network procurement processes are followed.

## Tendering Involving Related Parties

The protocols set out below will be implemented by Northpower Network in order to receive and evaluate bids from related parties alongside third party contractors on a fair and compliant basis.  These will also enable Northpower to mitigate process risks and enhance the attractiveness of the project for tenderers considering whether or not to submit a response.

- Disclosure that a related party has the capability to perform the project and will be invited to submit a bid.
- Disclosure of Evaluation Criteria in tender documents.
- Information barriers between Network and its related parties.
- Confidentiality undertakings required from Tenderers.
- Undertaking that pre-existing Intellectual Property is retained by Tenderers.
- Documentation of the Procurement Process to demonstrate probity.
- Briefings and de-briefings with successful and unsuccessful Tenderers.

**The following two protocols may also be considered for sensitive RFPs**

- Paying a stipend to Tenderers
- Appointing a Probity Adviser

# A description of how Northpower Network's related party policy is applied in practice

**(Clause 2.3.12.1 of EDID requirements)**

Large capital projects (typically a defined set of works with a value of over $1 million) conducted by Northpower Network are generally based on fixed price contracts. EDB management will determine whether these projects should be subject to a competitive tender process or negotiated directly with Northpower Network's contracting partner, Northpower Contracting Division. In assessing whether these projects should be subject to tender, the EDB considers:

- The urgency of the project in terms of network function and safety
- Contractor availability and capability
- Whether the project will be seen as attractive to external contractors. This review involves factors such as the size of the project, the number of crews required, the type of work being undertaken, travel and mobilisation costs.

Competitive tender processes follow established tender processes that are based on industry recognised tendering and contracting frameworks (generally Standard NZS3910). Northpower Contracting Division is given the option to participate in the competitive tender process.

The specialised nature of construction and maintenance services for the EDB, including management of safety risks, dynamic workflow requirements and short response times along with the value of the work offered and efficiency benefits, lends itself to Northpower EDB establishing a preferred supplier relationship for the procurement of these services. Northpower EDB has this relationship with Northpower Contracting, which means that they complete the majority of the EDB's capital (other than tendered) and maintenance work. The Northpower Contracting Division is an established provider of construction and maintenance services for electrical networks for a number of EDB's. This provides the capability and scale to ensure the division is well placed to provide high quality and efficient services.

Work negotiated directly with the Northpower Contracting Division's Northland region is based on negotiated labour, plant and unit rates. With the exception of tendered projects, all work completed by the Northpower Contracting's Northland region is governed by a field services agreement (referred to as the Service Level Agreement (SLA)). The SLA outlines how Northpower Network and Contracting's Northland region will work together, specifies the scope of services provided by the Contracting's Northland region, details rates, and includes a set of KPI's. The agreement is negotiated between representatives of the two Northpower divisions and approved by the respective General Managers. Work completed by Northpower Contracting's other regions is priced at the project rates offered to their local Network customers.

# A description of any Northpower Network policies or procedures that require or have the effect of requiring the consumer to purchase assets or goods or services from a related party

**(Clause 2.3.12.2 of EDID requirements)**

To work on or near Northpower's electricity distribution network, a contractor must be deemed competent and authorised to complete the work undertaken to satisfactorily meet Network standards.

Network extensions or customer initiated work must be undertaken by a Network approved contractor.

No external contractor is authorised for the following customer chargeable work:

a) HV network enhancements.

b) Third party network damage.

Due to risk to people and property and with any delay, no external contractor is authorised to remediate third party network damage. For completeness, the cost of remedying third party network damage, which is generally recovered from the responsible party, remains part of the services provided under the SLA.

# Representative examples of how Northpower Network's Related Party Policy has been applied for the procurement of assets or goods or services and how arm's length terms were tested

**(Clauses 2.3.12.3 – 2.3.12.5 of EDID requirements)**

## Capex Projects: Competitive Tender – Ngunguru Transformer and Switchboard upgrade

The upgrade of the Ngunguru transformer and switchboard was awarded under competitive tender using NZS3910 based tender process. The tender was offered to four established electrical contractors and released to three who elected to participate in the tender, including Northpower Contracting Division.

The award decision was based on weighted and objective criteria disclosed to the respondents in the tender documentation. Northpower Contracting Division was awarded this contract, based on the results of the tender process. The nature of the tender process provided an arms-length assessment for this contract. The notice of award was issued in March 2021 and construction was completed during FY22. This was the most recent tender process undertaken.

## Directly negotiated work with Northpower Contracting Division

Work completed by Northpower Contracting Division under direct negotiation is governed by a SLA and negotiated rates. Both the rates and SLA are negotiated between the divisional management teams and final approval is required from the General Managers of the respective divisions.

Northpower's Corporate Finance Division has completed industry benchmarking of the related party transactions between Northpower Network and Northpower Contracting Division for the year ended 31 March 2022. The Finance Division operates independently from Northpower Network and Contracting divisions and provides an impartial view. This arm's-length assessment focused on:

- Assessing how the Northpower Contracting Division sets rates charged to Northpower Network, compared to other customers;
- Comparing rates between a selection of customers;
- Comparing margins earned by the Northpower Contracting Division for a selection of customers;
- Comparing year-on year movements in rates by customer, labour type and unit cost type;
- Reviewing the management of the supplier relationship;
- Confirming the approval process of the SLA and agreed rates.

This assessment concluded that the related party transactions between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

## Opex Programme: Vegetation

Vegetation control for Northpower's EDB has been completed by Northpower Contracting Division and a third party.  An RFP was undertaken in June 22 and rates from Northern Contracting and two other external parties from the RFP were compared by Northpower's Corporate Finance Division.  This comparison concluded that the vegetation control rates between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

## Procurement Examples

The following provide examples of the procurement process for work completed by Northpower Contracting under the SLA.

### Faults Services

On 7 January 2022 at 17.59pm, the Control Room received a call from Fire and Emergency New Zealand reporting an incident where a vehicle collided with a pole on State Highway 14, Maungatapere (Pole no 58605) and requesting our attendance. The operator recorded this job in the faults management system under reference number 349971 and dispatched the standby faults crew consisting of 5 contractors to the site. Traffic management was also required while the pole was replaced.

Northpower Contracting recorded the labour, plant, equipment and materials used in replacing the pole as detailed on the service request. An invoice was issued to Network (Journal Batch #1072202) along with a copy of the unit rate billing sheet. This was approved for payment by Network. Northpower Network in turn invoiced the customer (Batch #1072283).

### Planned Maintenance

Northpower Network's maintenance is split between distribution and sub-stations. Each has an annual schedule of maintenance required. The maintenance tasks are created in our maintenance system, and are packaged into a work pack and issued to Northpower Contracting. The current process is that a purchase order (PO) is automatically created in the ERP system (JDE) when the work pack is issued. Work is completed by Northpower Contracting and any defects that require further follow up are recorded. Northpower Contracting raise an invoice, which is matched to the PO in the ERP system. The invoice is automatically approved if it matches the purchase order; otherwise, the invoices are manually reviewed and approved if the charges are appropriate. Invoices that require approval are highlighted in an exceptions report.

Defects identified when Northpower Contracting are completing the preventative maintenance tasks are recorded on a data sheet and Northpower Contracting create 'tasks' in Wasp (the asset maintenance system). These are then planned and packaged into work packs by Northpower Contracting and sent to the Network team for approval before being sent back to Northpower Contracting to carry out the work.

### Vegetation

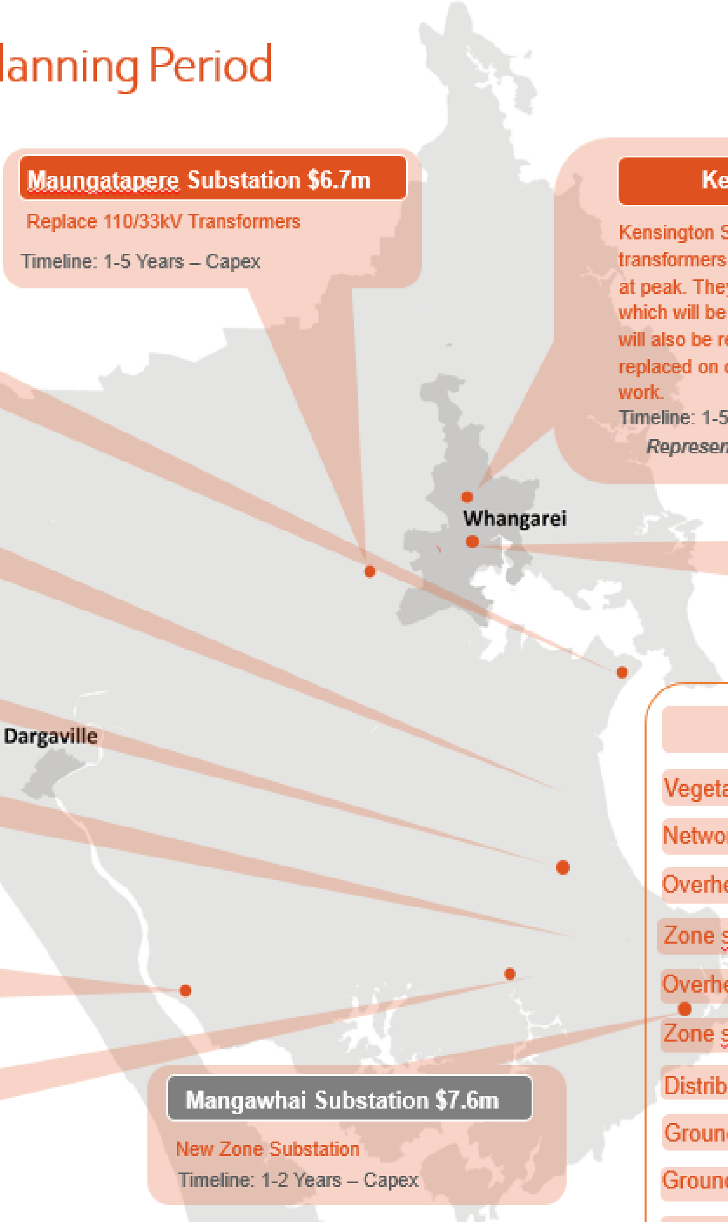
A prioritised annual vegetation maintenance programme is established for the year and non-urban work is distributed to Northpower Contracting for implementation. The programme is split into Feeder Lines and each is inspected in the order of Network's priority. Following inspection, details of any cutting work required is recorded in the maintenance system in a work pack. Once this work is completed, Northpower Contracting invoice Network. If the invoice is in line with purchase orders, they are auto approved. If there are variances Network management review and once the variance is understood and accepted the invoices are approved.

### Capital Project

There are routine sample tests carried out to identify conductors that are end of life. Conductors to include in conductor replacement projects are identified by the condition of the conductors and age. Network issue contracting a Project Job Sheet detailing works required. Northpower Contracting prepare a Project Work Proposal detailing the methodology, timeline and pricing to carry out the works. The Project Work Proposal is reviewed by Network, ensuring the proposal satisfies the requirements of the Project Job Sheet. If accepted, Network issues a purchase order accepting Northpower Contracting Project Work Proposal. Invoicing is done on a monthly basis as works are completed. Network approves the invoice if it is in line with the purchase order.

# Capex & Opex in AMP Planning Period

Northpower




**Bream Bay Substation $3.7m**

New 10 MVA Transformer Replace & 11kV Switchgear

Timeline: 1-5 Years – Capex

**Maungatapere Substation $6.7m**

Replace 110/33kV Transformers

Timeline: 1-5 Years – Capex

**Kensington Substation Upgrade $13m**

Kensington Substation upgrade includes replacement of two 110/33kV transformers due to these nearing end of life and reaching their capacity at peak. They will be replaced with two modern transformers each of which will be capable of carrying the full substation load. The 110kV bus will also be reconfigured. The existing 33kV Switchboard will be replaced on completion of the transformer replacement and 110kV bus work.

Timeline: 1-5 Years – Capex

*Representative example of a project in response to a network constraint*

**Waipu to Ruakaka $7.2m**

New 33kV line

Timeline: 6-10 Years – Capex

**Waipu Substation $6.7m**

New Zone Substation

Timeline: 6-10 Years - Capex

**Whangarei South Substation $4.7m**

Replace 33/11kV Transformers

Timeline: 4-6 Years - Capex

**Maungaturoto to Mangawhai $10m**

New 33kV Line

Timeline: 1-5 Years - Capex

**Ruawai Substation $3.8m**

Replace 33/11kV transformer & 11kV Switchboard

Timeline: 1-2 Years – Capex

**Maungaturoto Substation $5.0m**

Replace 11kV Switchboard & Transformers

Timeline: 1-5 Years - Capex

**Mangawhai Substation $7.6m**

New Zone Substation

Timeline: 1-2 Years – Capex

**OPEX Programme**

- Vegetation management $28.7m
- Network reactive maintenance (Faults) $25.4m
- Overhead network corrective maintenance $12.7m
- Zone substation preventive maintenance $7.0m
- Overhead network preventive maintenance $6.4m
- Zone substation corrective maintenance $4.1m
- Distribution earth maintenance $3.4m
- Ground mounted sub preventive maintenance $2.9m
- Ground mounted sub corrective maintenance $2.1m
- Pillar preventive maintenance $2.1m

Note:The OPEX Programme is not location based or in response to a constraint on the network

**Capital Project**
Currently not indicated for supply by a related party.

**Capital Project**
To be supplied by a related party.

**Operating Program**
With the exception of a small amount of vegetation management, this program is forecast to require the supply of assets or goods or services by a related party.

**DIRECTORS' CERTIFICATE**

We, Mark Trigg and Michael James, being Directors of Northpower Limited, certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) The historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the Northpower Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c) In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-

   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

| | |
|---|---|
| Director | Director |
| Mark Trigg | Michael James |
| Date 31 August 2022 | Date 31 August 2022 |

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Independent Assurance Report

**TO THE DIRECTORS OF NORTHPOWER LIMITED AND TO THE COMMERCE COMMISSION ON THE DISCLOSURE INFORMATION FOR THE DISCLOSURE YEAR ENDED 31 MARCH 2022 AS REQUIRED BY THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 (CONSOLIDATED 9 DECEMBER 2021)**

Northpower Limited (the 'Company') is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (the 'Determination') and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the Company.

The Auditor-General has appointed me, Silvio Bruinsma, using the staff and resources of Deloitte Limited, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the Company for the disclosure year ended 31 March 2022 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the 'IM Determination'), in respect of the basis for valuation of related party transactions (the 'Related Party Transaction Information').

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 17 May 2021 under clause 2.11 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the ID Determination, must take into account any issues arising out of the Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

**Opinion**

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;

- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the Company's accounting and other records, sourced from the Company's financial and non-financial systems;

- the Disclosure Information complies, in all material respects, with the Determination; and

- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

**Basis for opinion**

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) Assurance Engagements on Compliance, issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE (NZ) 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

**Key Assurance Matters**

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

| Key Assurance Matter | How our procedures addressed the key assurance matter |
|---|---|
| **Accuracy and completeness of the quantity and duration of electricity outages and ICP numbers**<br><br>The Information Disclosure Determination defines certain quality measures in relation to the number and duration of interruptions, faults, and causes of faults. These quality measures are expressed in the form of SAIDI and SAIFI values.<br><br>The accuracy of the data is a key audit matter because information on the frequency and duration of outages is an important measure about the reliability of electricity supply.<br><br>The completeness of the data is a key audit matter because the details of the faults are entered manually into the fault outage report, which is used to calculate the SAIDI/ SAIFI.<br><br>The feeder maps capture the Individual Connection Point data that is used in the calculation of the SAIDI and SAIFI values. These Feeder Maps are updated only once every 2 years. | We have:<br><br>• Obtained an understanding of the Company's methods by which electricity outages and their duration are recorded;<br>• Assessed the design and implementation of key controls related to the recording, reconciliation and review of the outage data obtained from the outage report;<br>• For a sample of outages, observed the number of consumers affected from the feeder maps on the date of testing and assessed the reasonability of this number against impacted consumers recorded in the data;<br>• Reviewed the recorded detail for a sample of outages and ensured that the appropriate dates and times were used and the outage was started and ended by an appropriate individual; and<br>• Recalculated the normalised SAIDI and SAIFI using the predetermined boundary limits. |

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| Valuation and identification of related party transactions | To evaluate valuation of related party transactions, we have: |
|---|---|
| The valuation of transactions with related parties ($11.3 million of purchases from related parties included in operating expenditures, and $17.0 million of assets acquired from related parties included into capital expenditure in the period) is a key assurance matter due to:<br><br>- the significant judgement in forming a view of related party pricing in the absence, or insufficiency, of publicly available information about pricing and terms of certain transactions.<br><br>The identification of transactions with related parties is a key assurance matter because Northpower Limited operate in a number of business areas and holds certain investments which may give rise to related party transactions with the electricity distribution business. | • Obtained an understanding of Northpower Limited's approach to identifying and valuing related party transactions in accordance with the Determination;<br>• Made a selection of related party transaction samples and performed analytical review to determine if the gross margins are in line with those charged to third parties, and compared the value of these transactions to at least one of the following:<br>  ○ the standard price list or standard rates obtained directly from the related party; or<br>  ○ the actual cost of providing the goods and service and observed margins applied for similar goods and services; or<br>  ○ the observed market price for similar goods or services.<br><br>To evaluate completeness of related party transactions, we have:<br><br>• Assessed whether all related party transactions had been included by comparing to our understanding of Northpower Limited's operating model; and<br>• Assessed whether all related party transactions recorded for financial reporting purposes had been correctly identified and disclosed. |

**Directors' responsibilities**

The directors of the Company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the Company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

**Auditor's responsibilities**

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems;

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the Company and, if not, the records not so kept;

- the Company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and

- the Company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE (NZ) 3100 (Revised), to obtain reasonable assurance about whether the Company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the Company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

**Inherent limitations**

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected. A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

**Restricted use**

This report has been prepared for use by the directors of the Company and the Commerce Commission in accordance with clause 2.8.1 (1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company and the Commerce Commission, or for any other purpose than that for which it was prepared.

**Independence and quality control**

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Deloitte Limited and its partners and employees may deal with the Company and its subsidiaries on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of trading activities of the Company, this engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company or its subsidiaries.

Silvio Bruinsma

Silvio Bruinsma
**Deloitte Limited**
On behalf of the Auditor-General
Auckland, New Zealand
31 August 2022

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## Report of the Independent Appraiser

**TO THE DIRECTORS OF NORTHPOWER LIMITED AND TO THE COMMERCE COMMISSION ON THE RELATED PARTY TRANSACTIONS FOR THE DISCLOSURE YEAR ENDED 31 MARCH 2022 AS REQUIRED BY THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 (CONSOLIDATED 9 DECEMBER 2021)**

Northpower Limited (the 'Company') is required to procure an assurance report by an independent appraiser on the related party transactions of the Company for the disclosure year ended 31 March 2022.

The Auditor-General is the auditor of the Company.

The Auditor-General has appointed me, Silvio Bruinsma, using the staff and resources of Deloitte Limited, to undertake a reasonable assurance engagement, on his behalf, on:

- whether the Company's related party transactions for the disclosure year ended 31 March 2022, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (the 'Information Disclosure Determination') and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the 'Input Methodologies Determination'); and.

- whether the steps taken by the Company, as specified under the "Description of steps and analysis undertaken by the Company" are considered to be, in all material respects, reasonable in the circumstances.

**Opinion**

In our opinion, in all material respects:

- based on the information we have obtained, the related party transactions we have sampled and the analysis we have undertaken, the Company's related party transactions for the disclosure year ended 31 March 2022, comply with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and

- the steps taken by the Company, as specified under the "Description of steps and analysis undertaken by the Company" are considered to be reasonable in the circumstances.

**Basis for opinion**

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) Assurance Engagements on Compliance, issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE (NZ) 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

**The key assumptions we made in carrying out our work**

In carrying out our work we have assumed that the Company's internal controls that we tested, and placed reliance on, during our audit of the financial statements for the year ended 31 March 2022 also applied in relation to our work as the independent appraiser for the disclosure year ended 31 March 2022.

In building on this assumption, we have carried out specific tests to assess if the Company has identified related parties and related party transactions during the disclosure year ended 31 March 2022.

**How we sampled the Company's related party transactions**

For the material related-parties who provided, or acquired, a material value of goods and services to or from the Company, we selected a small sample of related-party transactions to assess if they had been valued in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

**Description of steps and analysis undertaken by the Company**
The process to ensure transactions were on an arm's length basis are set out in Northpower Limited's Network Procurement policy for Related Parties.

Methods available to be used include any or all of the following depending on the nature of the proposed transaction, the information reasonably available and what is practicable in the circumstances given the market for the relevant services:

- Conducting a tendering process for the goods or services (not utilised during the 31 March 2022 disclosure year);
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by the related party to its other customers (utilised for the majority of transactions during the 31 March 2022 disclosure year);
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by similar external providers (not utilised during the 31 March 2022 disclosure year);
- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or services (not utilised during the 31 March 2022 disclosure year); and
- Engaging an expert to undertake an independent valuation to determine market value of the goods or service (not utilised during the 31 March 2022 disclosure year).

To further assess whether the Service level agreement, and other related party transactions, were at arm's length, an internal benchmarking review was completed. The rates applied, in the Service Level Agreement with Northpower Contracting Limited, were compared to rates agreed in third party service level agreements for similar work.

**Directors' responsibilities**

The directors of the Company are responsible for:

- the identification of related-parties and related-party transactions during the disclosure year ended 31 March 2022; and
- the valuation of goods and services acquired from or supplied to a related party, in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

The directors of the Company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

**Auditor's responsibilities**

Our responsibility is to prepare a report that provides reasonable assurance on whether:

- the Company's related party transactions for the disclosure year ended 31 March 2022, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and
- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

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An assurance engagement to report on the Company's compliance with the Information Disclosure Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

**Inherent limitations**

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance may occur and not be detected.

We did not examine every related party transaction, nor do we guarantee complete accuracy of the related-party disclosures.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance will continue in the future.

**Restricted use**

This report has been prepared for use by the directors of the Company and the Commerce Commission in accordance with clause 2.8.4 of the Information Disclosure Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company and the Commerce Commission, or for any other purpose than that for which it was prepared.

**Independence and quality control**

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Deloitte Limited and its partners and employees may deal with the Company and its subsidiaries on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of trading activities of the Company, this engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company or its subsidiaries.

Silvio Bruinsma
**Deloitte Limited**
On behalf of the Auditor-General
Auckland, New Zealand
31 August 2022