Northpower

2025-2035 Asset Management Plan Update

March 2025

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Section 1:

Asset Management Plan Update

1. Asset Management Plan Update

This supplement to our Asset Management Plan, published in March 2023 for the period 2024-2033 and subsequently in March 2024 for the period 2025-2034, provides an update to Northpower's approach to managing its assets and delivering the planned programmes of capital and operational spend, as well as planned maintenance work for the period 1 April 2025 to 31 March 2035.

Northpower's 2023 Asset Management Plan is available from Northpower's website at: northpower.com/company/disclosures. This update should be read in conjunction with the 2023 AMP and outlines how we are managing our Network assets for the efficient and reliable delivery of electricity to consumers.

Covered in this update are:

1. Our improvements underway that will be included in our next full AMP (in 2026)
2. Material changes to the network development plans disclosed in the last AMP
3. Material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP
4. Material changes to Northpower's asset management practices; and
5. An outline of the reasons for material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b.

Information disclosure requirements

Our AMP update is written in accordance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. Clause 2.6.3 of this document requires that Northpower publicly disclose an AMP Update prior to 1 April 2025.

Clause 2.6.5 states that the AMP update must:

1. Relate to the electricity distribution services supplied by the EDB
2. Identify any material changes to the network development plans disclosed in the last AMP under clause 11 of Attachment A or in the last AMP update disclosed under this clause
3. Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 12 of Attachment A
4. Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b
5. Identify any changes to the asset management practices of the EDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure and
6. Contain the information set out in clause 2.6.6 which are schedules 11a, 11b, 11c, 12a, 12b, 12c and 12d

Clause 2.7.2 also requires that the Mandatory Explanatory Notes on Forecast Information in Schedule 14a is publicly disclosed prior to the start of each disclosure year.

Stakeholder feedback

Northpower encourages feedback to enable continued improvement in meeting the needs of its consumers and stakeholders.

Feedback should be addressed to:

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General Manager – Network Investment & Strategy

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Section 2:

Our Next Asset Management Plan

2. Our Next Asset Management Plan

We are continuing to work on several initiatives to improve our asset management that will be included in our next full asset management plan in 2026. These are outlined in the following sections:

Customer engagement

- **Customer notifications:** Through our ongoing surveys and customer engagement, customers tell us that communication is important, and they particularly need up to date and accurate information about outages (both planned and unplanned). Our investment in a Customer Relationship Management (CRM) system in recent years means we are now able to integrate this with our new outage management system and provide up to date information to customers about planned and unplanned outages. This will enable an improved customer experience with up to the minute outage information available on our website.
- **New website:** We are continuing the rollout of a new website, which includes a revamped outage centre where the aforementioned information will be easily accessible. Work is ongoing to enhance the outage centre, enabling customers to access information specific to their connection. The website will also provide comprehensive details, covering everything from obtaining a new connection or gaining approval for solar installations to guidance for property developers and advice on working safely around our network.
- **Helping customers navigate their energy choices:** We recognise that energy hardship is a serious issue in our communities and one of our key goals is to reduce total energy costs for consumers.

  Northpower is continuing with our successful consumer outreach programme, where energy assessors visit homes providing practical energy saving advice and energy saving devices such as LED bulbs and energy-efficient shower heads to help customers reduce their total electricity costs. Over the past three years, Northpower has been awarded $0.38M funding from the Government's Support for Energy Education in Communities (SEEC) programme to support this activity. To date we have completed assessments of over 3,800 homes, and provided energy saving devices, saving these homes an estimated total $3.16M in power bills every year.

Risk management

- **Asset health modelling:** We are continuing to enhance our asset health models by expanding the range of analytical factors considered in each model. This approach will provide us an improved understanding of asset performance, increase the accuracy of our degradation forecasting and improve our asset replacement timelines. Additionally, as part of our ongoing development, we are updating defect classification catalogue and testing it in our lidar and pole-top imagery pilot project. This initiative will refine our ability to detect asset defects while enabling a better risk prioritisation for asset replacement. The ongoing model refinement will conclude in a comprehensive integration of the results into the AMP 2026. This will represent our commitment to a data-driven approach to asset management.
- **Communication network:** We have completed the development of our communication framework, assessing our network communication infrastructure risk, and overall resilience. Several new initiatives were identified and incorporated into our 10-year capital expenditure plan. We continue to develop our communication strategy, aligning current infrastructure with future communication requirements.
- **Critical & Strategic Spares Strategy:** We have developed and finalised our critical and strategic spare strategy, focusing on identified spares to improve availability and enhance our current spares programme. In the next two phases of the project, we will continue to develop our critical spares management plan and create strategic spare business cases, which will be included in the full Asset Management Plan in 2026.
- **Network resilience:** We continue our work on building the resilience of the network, including carrying out risk studies on strategically important assets on our network, enabling better back-feed capability on both the subtransmission and distribution network, and updating our design standards to ensure our assets are fit for purpose for the future. We are also collaborating with both Transpower and Top Energy to develop our integrated plan for improving renewable energy generation and transmission infrastructure in the Northland region.

Network development

- **Low voltage (LV) network management:** In 2023 we completed a proof of value trial using smart meter data & analytics software. Following this trial we have purchased smart meter data for roughly 60% of the network and have commenced several more trials with analytic software companies. Since purchasing this data, we have been able to better understand our LV and distribution networks, we have begun identifying and mapping existing and future constraints. We are also continuing to explore additional use cases for the data. This data is quickly proving its worth and allows us to better understand customer behaviours which allows Northpower to manage the uptake of EVs and solar effectively.
- **Decarbonisation:** We have continued our communication with load customers who have the potential for an increase in demand due to decarbonisation. Currently these customers decarbonisation initiatives are well aligned with Northpower own demand forecasts. In 2023, the Energy Efficiency and Conservation Authority (EECA) published a report for Northland assessing the region's potential for decarbonisation, for upcoming projects Northpower considers this report and will allow spare capacity where economically feasible.
- **Reliability:** Northpower has launched a new strategy to enhance the reliability of the distribution network. This strategy prioritises improving our ability to locate and isolate faults more rapidly, as well as restoring service to unaffected customers. It focuses on increasing automation across the distribution network by ensuring all 11kV feeders are equipped with automated mid-point and tie-point switches, along with fault passage indicators (FPIs) to assist with fault location. A project has been initiated to align the network with this strategy over the next two financial years.

Lifecycle management

- **Asset strategies:** We are continuing to develop a set of asset strategies that outline our approach to managing assets throughout their lifecycle across various asset classes. These strategies cover a range of assets, from high-value, high-consequence equipment typically found in zone substations to our extensive fleet of volumetric assets. They assess current objectives and their alignment with our practices, identifying opportunities for future improvements across our asset portfolios.
- **Asset condition assessment:** Working through our asset health models, we identified the need of obtaining more comprehensive condition data for our Network. Moreover, during the Summer FY25 we initiated a trial considering alternative methods to inspect and record network condition data. The outcome of the trial will support our continuous improvement of asset data and potentially enhance our current data collection approach.
- **Vegetation management:** We are continuing to implement our risk-based approach to vegetation management, which prioritises the removal of high-risk vegetation. We are also in the process of aligning our vegetation management plan with the new Tree Regulations. Further details will be provided in the 2026 Asset Management Plan.

Supporting activities

- **Drawings management:** A specialist engineering drawings management system, Autodesk Vault, was introduced in FY24. This was followed by a comprehensive review and upload of substation drawings and associated metadata into Vault. The migration phase is planned for completion in March 2025. FY26 will see Vault fully implemented with BAU processes delivering change control, version control, and structured workflows.
- **ADMS:** The third and final phase of our Advanced Distribution Management System (ADMS) has been completed. This phase implemented an Outage Management System (OMS) integrated with our Salesforce CRM and website/phone system, Advanced Applications including Distribution Power Flow, and also provides accurate regulatory and real-time reporting on outages. This allows our call operators full visibility of network outages and integrates multiple outages to identify the resultant asset.
- **Asset management information system (AMIS):** We have completed the System Selection and Design phases of the project and will proceed with implementing the Maximo system during FY26. The first phase encompasses scoping and design, followed by the implementation.

Section 3:

Material Changes

3. Material Changes

3.1 Overview

Since the 2024 AMP Update, we have continued to review the existing Asset Management Plan for the electricity business, including our approach to investment and maintenance, with a focus on continual improvement.

The key inputs into this review have included:

- A review of forecast changes in investment need relating to asset renewal and load growth for the 10-year planning period FY26-FY35.
- A review of unit costs associated with our investment programmes has been undertaken, noting that Northpower has experienced significant cost increases across the board in recent years. We have completed updates to the costs for our major substation projects and are currently reviewing and updating unit rates for our high-volume distribution assets.
- We have also concluded our RFP process for both the Asset Management Information System replacement and the LiDAR and pole-top imagery project, and have updated our budget to reflect the more accurate but higher requirements.
- Reviewing security of supply criteria against updated demand forecasts.
- A review of Opex and Capex programs to ensure SAIDI and SAIFI remain in line with long-term averages, taking into account an aging asset base, increases in planned work and ongoing vegetation challenges.

This 2025 AMP Update summarises the resulting changes to our Asset Management Plan.

3.2 Material changes to network development plan

Overall $0.9M increase in the 10-year Network Development profile compared with the 2024 Asset Management Plan Update[1]

We have revisited growth forecasts to validate the need for our Network development investments for the next 10-year period, updated our cost estimates and revalidated our plan. The majority of the changes relate to updated cost estimates reflecting new information from recent projects or updated scope following further investigation. The material changes to the plan are outlined in the below table.

[1] For the comparison period FY25 to FY34

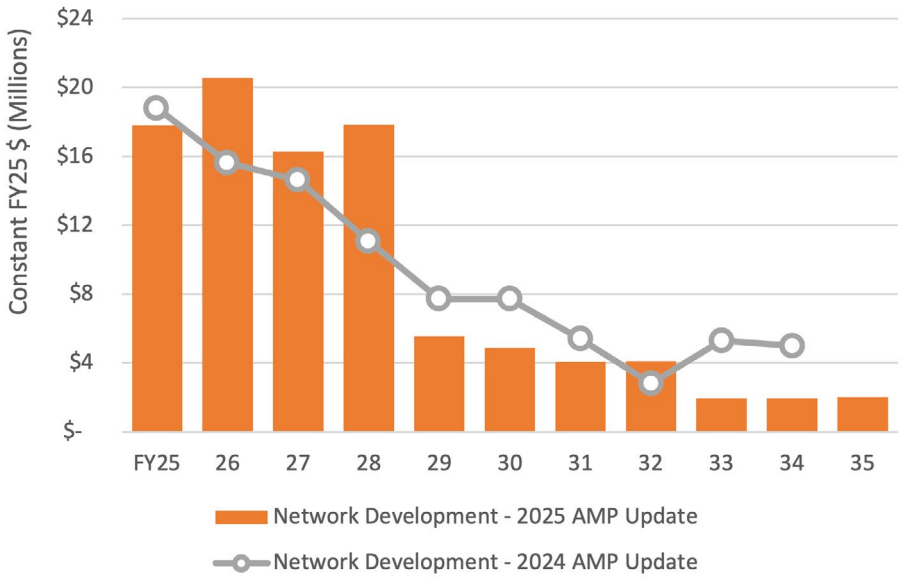
Material changes to network development plan[2]

Year	Change ($)	Description of change	Reasons for change
FY24-FY28	+$3.2M	Cost update - Mangawhai New 33kV Line Build	Our previous AMP indicated an increase to the project cost, as we have progressed into the detailed design we have refined the cost estimate further.
FY26	+1.4M	Scope Change – 11kV Mid & Tie Remote Controlled Switching	We have set a new resilience strategy which requires every distribution feeder to have both the mid and tie point equipped with remote-controlled switches. Northpower aims to align to this strategy over the course of FY26.
FY26	+2.8M	Scope Change - Restore the 33kV Sub-Transmission line between Maungatapere and Whangarei South.	During the concept design, the preferred option was deemed not viable. Alternative options require significant changes to the cable route significantly increasing the project cost.
FY28-FY30	+2.1M	New Project - Mangawhai Existing 33kV Line Upgrade	A new project has been added to the growth forecast, on completion of the new 33kV line build we will start the upgrade of the existing 33kV line. This project is to allow for N-1 security for the Mangawhai area.
FY28-FY32	+$4.3M	Cost update - Replacement of both Kensington to Tikipunga Oil Cables.	Since the last AMP update, the scope was updated to include the replacement of the second oil cable.
FY29-FY31	-7.4M	Project deferral – Waipa to Ruakaka 33kV Line & Easements	The anticipated new load has not materialised as projected, with growth occurring at a slower pace. This has resulted in the deferral of the 33kV line upgrade and the development of the new Waipa zone substation. Current projections have been revised to FY37–FY39.
FY32-FY34	-7.1M	Project deferral – Waipa Zone Substation	

The resulting investment profile sees an uplift in investment related to Network Development compared with our 2024 AMP Update.

[2] Includes the following investment categories: consumer connections, system growth, asset relocations, reliability, safety & environment

10-Year Network Development Investment Profile (2025 AMP Update vs. 2024 AMP) - $M



3.3 Material changes to asset lifecycle management

Overall $4.2M increase in the 10-year Asset Life Cycle Management profile compared with the 2024 Asset Management Plan Update.[3]

We have updated our asset models with new asset information, updated our cost estimates and revalidated our asset renewal forecasts. We have also reviewed and updated our non-network assets forecasts.

The key resulting changes to our plan are outlined in the below table.

[3] For the comparison period FY25 to FY34

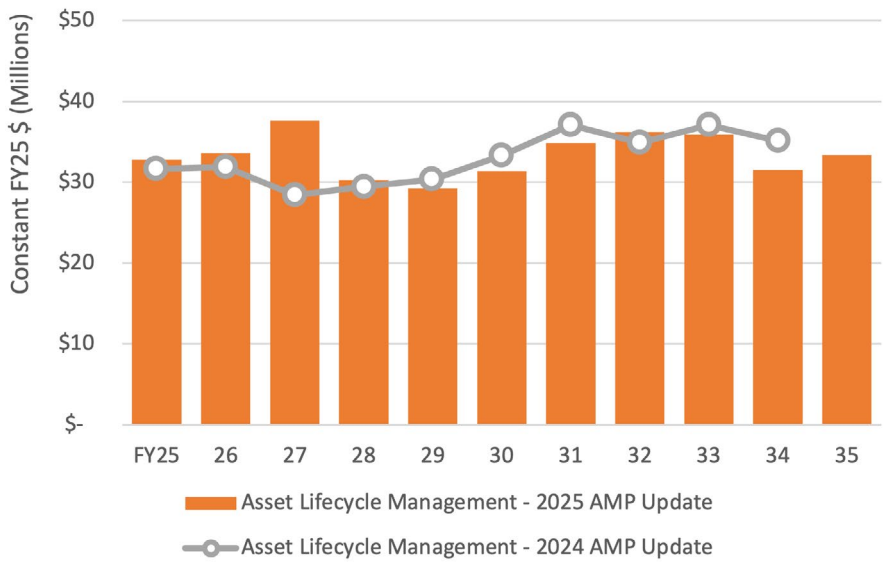
Material changes to asset life cycle management plan[4]

Year	Change ($)	Description of change	Reasons for change
All	+2.1M	Budget adjustment – Strategic Spares	To support and implement our new strategic spares strategy, additional funding has been allocated for the procurement of critical and strategic spares.
All	+$2.4M	Allowance for Network System Upgrades and implementation	Our previous forecast did not make allowance for long term capital expenditure on system upgrades and implementation beyond the next 3-4 years, as it is difficult to forecast. A modest allowance has been made for this work over the 10-year period.
FY25-FY27	+2.7M	Cost update – AMIS Replacement	The cost update for replacing the Asset Management Information System is based on recent RFP pricing obtained from the concept design stage.
FY25-FY27	-$0.9k	Scope Change – Chip Mill Transformer & switchgear replacement	The scope has been revised to include a supply change for Chipmill substation, altering the supply from 33kV to 11kV and removing the power transformer
FY26-FY27	+1.2M	Cost update – LiDAR & Poletop Imagery	The cost update for implementing the LiDAR and Poletop Imagery project is based on recent RFP pricing obtained from the concept design stage.
FY26-FY27	+$1.3M	Cost Update – Project move from design to implementation phase for the Kensington 33kV switchboard replacement	Updated pricing from design stage to construction
FY27-FY28	+$1M	New Project – Replacement of Core GIS system	Replacement of the existing GIS system which have become obsolete
FY30-FY31	-2.3M	Project deferral – Ruakaka T2 transformer replacement	Deferred the replacement of the transformer at Ruakaka zone substation to FY35-FY37.
FY30-FY33	-$1.8M	Budget adjustments - have been made due to updates in cost estimations and the deferral of project delivery, impacting switchboard replacements	Cost increases have arisen from updates to our cost estimations for switchgear replacements, impacting the 33kV switchboards at the Alexander Street, Bream Bay, and Maungatapere substations. The 11kV switchboards at Mareretu and Kioreroa have been deferred.

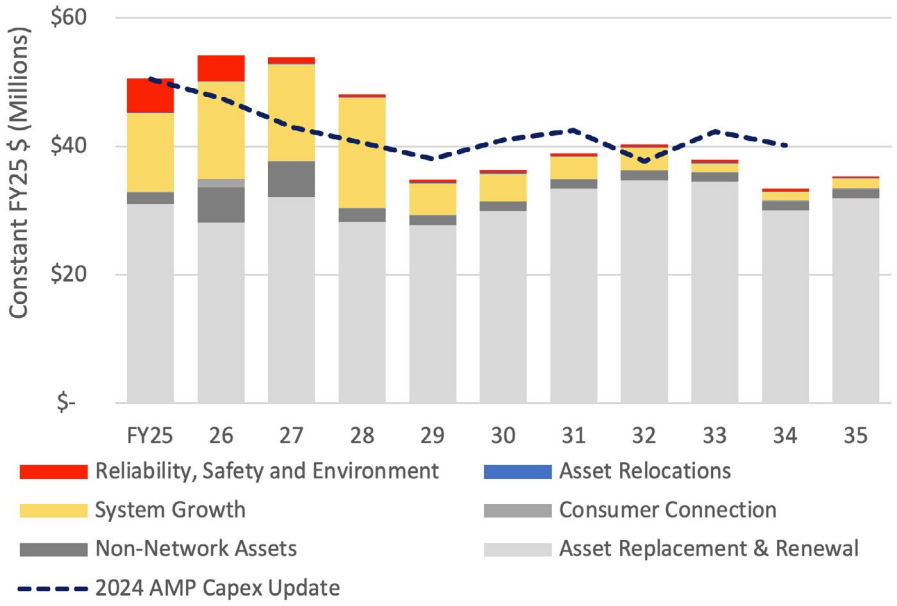
The resulting investment profile sees an uplift in investment related to Asset Lifecycle Management, compared with our 2024 AMP Update across the planning period.

[4] Includes the following investment categories: asset replacement and renewal, non-network assets

10-year asset life cycle management investment profile (2025 AMP update vs. 2024 AMP update) - $M



Forecast Capex expenditure 2025 AMP Update vs. 2024 AMP Update



3.4 Material changes to expenditure forecasts (Schedule 11a and 11b)

Compared to the 2024 AMP Update we are forecasting an decrease across Capex with no significant change in Opex expenditure.

- The reasons for the Capex increase are detailed in sections 3.2 and 3.3.
- The reasons for the Opex increase are detailed at the end of this section.

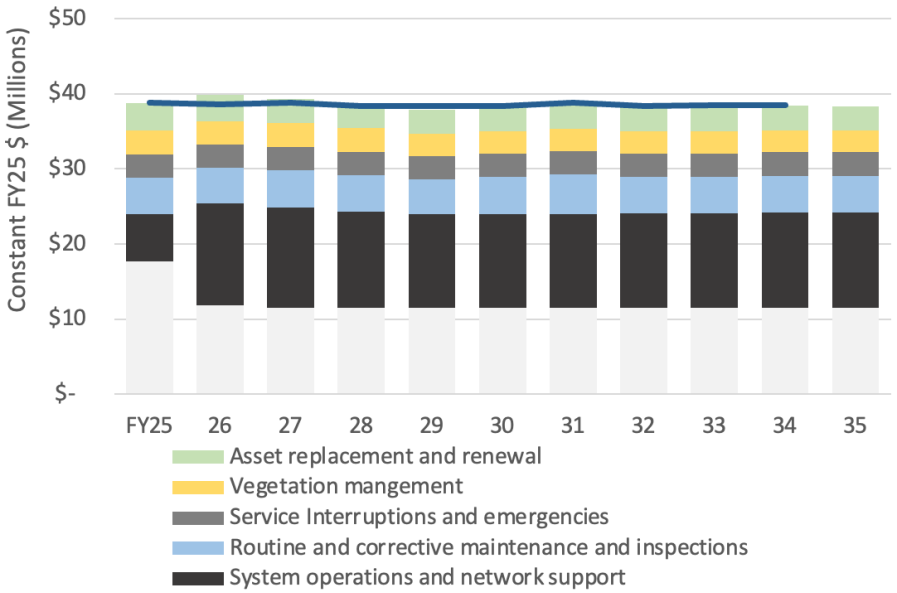
Capex Expenditure Forecast

The 10-year forecast capital expenditure is $413M for the period FY26-FY35, down $10.2M from the 2024 AMP Update (for the period FY25-FY34) and is shown below.

Opex Expenditure Forecast

The 10-year forecast operational expenditure is $385.5M for the period FY26-FY35, up $0.1M from the 2024 AMP Update (for the period FY25-FY34) and is shown below.

Forecast Capex expenditure 2025 AMP Update vs. 2024 AMP Update



There are no significant changes to the Operational budget.

3.5 Material changes to asset management practices

There have been no material changes in our Asset Management Practices since our 2024 AMP Update. However, as outlined in the "Our Next Asset Management Plan" section, we are working on several initiatives to improve our asset management approach and these will be discussed further in our next full AMP in 2026.

Section 4:

Schedules

4.1 Schedule 11a: report on forecast Capital Expenditure

Company Name	**Northpower**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			1.000	1.035	1.056	1.077	1.098	1.120	1.143	1.166	1.189	1.213	1.237
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8													
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	3,119	4,480	3,569	4,003	4,490	5,037	6,643	6,776	6,912	7,050	7,191
11		System growth	12,244	15,639	15,908	18,547	5,412	4,756	3,957	4,062	1,590	1,621	1,901
12		Asset replacement and renewal	30,955	29,094	33,858	30,353	30,498	33,540	38,140	40,493	40,972	36,412	39,461
13		Asset relocations	166	124	127	129	132	134	137	140	143	146	148
14		Reliability, safety and environment:											
15		Quality of supply	3,440	3,150	831	33	34	34	35	36	36	37	38
16		Legislative and regulatory	848	47	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	954	927	211	383	391	399	407	415	423	432	247
18		**Total reliability, safety and environment**	5,243	4,124	1,042	416	425	433	442	451	460	469	285
19		**Expenditure on network assets**	51,727	53,461	54,503	53,449	40,957	43,900	49,319	51,922	50,076	45,697	48,986
20		**Expenditure on non-network assets**	1,806	5,686	5,841	2,229	1,593	1,624	1,657	1,690	1,724	1,758	1,794
21		**Expenditure on assets**	53,533	59,148	60,344	55,678	42,549	45,524	50,976	53,612	51,800	47,456	50,780
22													
23	*plus*	Cost of financing	1,374	1,574	1,579	1,396	1,073	1,142	1,191	1,258	1,206	1,050	1,133
24	*less*	Value of capital contributions	3,064	3,171	3,558	3,992	4,479	5,026	6,632	6,764	6,900	7,038	7,178
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	51,843	57,550	58,365	53,082	39,144	41,640	45,535	48,106	46,106	41,468	44,734
28													
29		Assets commissioned	41,078	46,373	69,905	69,841	34,774	42,708	42,162	46,655	46,285	40,675	41,161
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31													
32			**$000 (in constant prices)**										
33		Consumer connection	3,119	4,329	3,380	3,717	4,088	4,496	5,813	5,813	5,813	5,813	5,813
34		System growth	12,244	15,111	15,069	17,224	4,928	4,245	3,463	3,485	1,337	1,337	1,537
35		Asset replacement and renewal	30,955	28,110	32,071	28,188	27,767	29,938	33,376	34,741	34,463	30,026	31,902
36		Asset relocations	166	120	120	120	120	120	120	120	120	120	120
37		Reliability, safety and environment:											
38		Quality of supply	3,440	3,043	787	31	31	31	31	31	31	31	31
39		Legislative and regulatory	848	45	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	954	896	200	356	356	356	356	356	356	356	200
41		**Total reliability, safety and environment**	5,243	3,984	987	387	387	387	387	387	387	387	231
42		**Expenditure on network assets**	51,727	51,653	51,627	49,636	37,289	39,185	43,159	44,546	42,120	37,683	39,603
43		Expenditure on non-network assets	1,806	5,494	5,533	2,070	1,450	1,450	1,450	1,450	1,450	1,450	1,450
44		**Expenditure on assets**	53,533	57,147	57,160	51,706	38,739	40,635	44,609	45,996	43,570	39,133	41,053
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses											
49		Overhead to underground conversion											
50		Research and development											
52													

4.1 Schedule 11a: report on forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	152	188	286	402	541	830	963	1,098	1,236	1,377
System growth	-	529	839	1,323	485	511	494	577	253	284	364
Asset replacement and renewal	-	984	1,786	2,165	2,731	3,602	4,764	5,752	6,510	6,386	7,558
Asset relocations	-	4	7	9	12	14	17	20	23	26	28
Reliability, safety and environment:											
Quality of supply	-	107	44	2	3	4	4	5	6	7	7
Legislative and regulatory	-	2	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	31	11	27	35	43	51	59	67	76	47
Total reliability, safety and environment	-	139	55	30	38	47	55	64	73	82	55
Expenditure on network assets	-	1,808	2,876	3,813	3,667	4,715	6,160	7,376	7,956	8,014	9,383
Expenditure on non-network assets	-	192	308	159	143	174	207	240	274	308	344
Expenditure on assets	-	2,000	3,184	3,972	3,810	4,889	6,367	7,616	8,230	8,322	9,726

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

*Consumer types defined by EDB**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
Consumer connections (gross)	3,064	3,064	3,370	3,707	4,078	4,486
Easements (Consumer Connections)	10	10	10	10	10	10
Vested Assets (Connections)	45	1,255				
Consumer connection expenditure	3,119	4,329	3,380	3,717	4,088	4,496
less Capital contributions funding consumer connection	2,974	2,974	3,280	3,617	3,988	4,396
Consumer connection less capital contributions	145	1,355	100	100	100	100

*include additional rows if needed

11a(iii): System Growth

Subtransmission	2,980	6,816	7,906	9,376	3,598	2,915
Zone substations	6,892	6,656	5,856	6,541	23	23
Distribution and LV lines	1,125	182	100	100	100	100
Distribution and LV cables	-	-	-	-	-	-
Distribution substations and transformers	1,247	1,207	1,207	1,207	1,207	1,207
Distribution switchgear	-	250	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	12,244	15,111	15,069	17,224	4,928	4,245
less Capital contributions funding system growth						
System growth less capital contributions	12,244	15,111	15,069	17,224	4,928	4,245

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
11a(iv): Asset Replacement and Renewal	**$000 (in constant prices)**					
Subtransmission	3,511	2,014	3,840	1,156	502	508
Zone substations	7,932	8,594	7,607	3,404	2,739	4,584
Distribution and LV lines	10,718	13,918	16,365	18,860	19,949	20,242
Distribution and LV cables	2,330	529	241	299	368	451
Distribution substations and transformers	2,845	1,406	1,810	2,085	1,710	1,605
Distribution switchgear	3,538	1,563	2,123	2,300	2,415	2,463
Other network assets	81	85	85	85	85	85
Asset replacement and renewal expenditure	30,955	28,110	32,071	28,188	27,767	29,938
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	30,955	28,110	32,071	28,188	27,767	29,938

4.1 Schedule 11a: report on forecast Capital Expenditure (continued)

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	Asset Relocations	166	120	120	120	120	120
	*include additional rows if needed						
	All other project or programmes - asset relocations						
	Asset relocations expenditure	166	120	120	120	120	120
less	Capital contributions funding asset relocations						
	Asset relocations less capital contributions	166	120	120	120	120	120

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	All QoS projects	3,440	3,043	787	31	31	31
	*include additional rows if needed						
	All other projects or programmes - quality of supply						
	Quality of supply expenditure	3,440	3,043	787	31	31	31
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	3,440	3,043	787	31	31	31

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	4-Block AUFLS	848	45	-	-	-	-
	*include additional rows if needed						
	All other projects or programmes - legislative and regulatory						
	Legislative and regulatory expenditure	848	45	-	-	-	-
less	Capital contributions funding legislative and regulatory						
	Legislative and regulatory less capital contributions	848	45	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	All ORSE projects	954	896	200	356	356	356
	*include additional rows if needed						
	All other projects or programmes - other reliability, safety and environment						
	Other reliability, safety and environment expenditure	954	896	200	356	356	356
less	Capital contributions funding other reliability, safety and environment						
	Other reliability, safety and environment less capital contributions	954	896	200	356	356	356

4.1 Schedule 11a: report on forecast Capital Expenditure (continued)

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
169							
170							
171							
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	Routine expenditure	160	190	150	150	150	150
176							
177							
178							
179							
180	*include additional rows if needed						
181	All other projects or programmes - routine expenditure						
182	**Routine expenditure**	160	190	150	150	150	150
183	**Atypical expenditure**						
184	*Project or programme**						
185	Atypical expenditure	1,647	5,304	5,383	1,920	1,300	1,300
186							
187							
188							
189							
190	*include additional rows if needed						
191	All other projects or programmes - atypical expenditure						
192	**Atypical expenditure**	1,647	5,304	5,383	1,920	1,300	1,300
193							
194	**Expenditure on non-network assets**	1,806	5,494	5,533	2,070	1,450	1,450

4.2 Schedule 11b: report on forecast Operational Expenditure

Company Name	**Northpower**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		3,099	3,213	3,277	3,343	3,410	3,478	3,547	3,618	3,691	3,765	3,840
11	Vegetation management		3,161	3,304	3,371	3,196	3,260	3,326	3,392	3,460	3,529	3,600	3,672
12	Routine and corrective maintenance and inspection		4,926	4,860	5,199	5,163	5,068	5,565	6,054	5,674	5,727	6,012	6,027
13	Asset replacement and renewal		3,704	3,600	3,388	3,456	3,525	3,595	3,666	3,739	3,814	3,890	3,967
14	**Network Opex**		14,891	14,977	15,235	15,158	15,263	15,963	16,659	16,492	16,761	17,266	17,505
15	System operations and network support		6,224	14,049	14,130	13,813	13,702	13,987	14,288	14,609	14,953	15,323	15,727
16	Business support		17,692	12,248	12,149	12,405	12,653	12,906	13,164	13,427	13,696	13,970	14,249
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
18	**Non-network opex**		23,916	26,297	26,279	26,218	26,355	26,893	27,452	28,036	28,648	29,292	29,976
19	**Operational expenditure**		38,807	41,274	41,515	41,376	41,618	42,856	44,112	44,528	45,409	46,559	47,481
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		3,099	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104	3,104
24	Vegetation management		3,161	3,193	3,193	2,968	2,968	2,968	2,968	2,968	2,968	2,968	2,968
25	Routine and corrective maintenance and inspection		4,926	4,695	4,925	4,795	4,614	4,967	5,297	4,868	4,817	4,958	4,872
26	Asset replacement and renewal		3,704	3,478	3,210	3,209	3,209	3,209	3,209	3,208	3,208	3,208	3,207
27	**Network Opex**		14,891	14,470	14,432	14,077	13,896	14,249	14,579	14,149	14,098	14,238	14,152
28	System operations and network support		6,224	13,567	13,378	12,810	12,452	12,462	12,481	12,512	12,555	12,615	12,695
29	Business support		17,692	11,860	11,529	11,530	11,530	11,530	11,530	11,530	11,530	11,530	11,530
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
31	**Non-network opex**		23,916	25,427	24,907	24,340	23,982	23,991	24,011	24,041	24,085	24,145	24,224
32	**Operational expenditure**		38,807	39,897	39,339	38,416	37,878	38,240	38,590	38,190	38,183	38,383	38,377
33	**Subcomponents of operational expenditure (where known)**												
35	Energy efficiency and demand side management, reduction of energy losses												
36	Direct billing*												
37	Research and Development												
38	Insurance												
39													
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	109	173	238	305	374	443	514	586	660	735
47	Vegetation management		-	112	178	228	292	357	424	492	561	631	703
48	Routine and corrective maintenance and inspection		-	164	274	368	454	598	756	806	910	1,054	1,154
49	Asset replacement and renewal		-	122	179	247	316	386	458	531	606	682	760
50	**Network Opex**		-	506	804	1,081	1,367	1,714	2,081	2,343	2,663	3,028	3,353
51	System operations and network support		-	482	752	1,003	1,250	1,525	1,807	2,098	2,397	2,708	3,032
52	Business support		-	388	620	875	1,123	1,376	1,634	1,897	2,166	2,440	2,719
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	870	1,372	1,878	2,373	2,901	3,442	3,995	4,563	5,148	5,751
55	**Operational expenditure**		-	1,377	2,176	2,960	3,740	4,616	5,522	6,338	7,226	8,176	9,104
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*												

4.3 Schedule 12a: report on asset condition

Company Name	**Northpower**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)							
	Voltage	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.27%	0.58%	3.09%	9.30%	86.75%		3	1.54%
11	All	Overhead Line	Wood poles	No.	3.61%	6.78%	20.33%	26.83%	42.46%		3	16.62%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-			-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.24%	2.81%	13.16%	23.25%	59.53%		3	7.31%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0.09%	0.30%	3.51%	17.65%	78.45%		3	0.90%
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	4.86%	78.23%	16.91%		3	0.09%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	98.87%	1.13%	-		4	45.04%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-			-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-		4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	100.00%	-		4	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-			-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-			-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-			-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	100.00%	-		4	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	4.55%	-	36.36%	50.00%	9.09%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-		4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	31.58%	36.84%	-	31.58%		4	21.05%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	1.72%	15.52%	82.76%		4	1.72%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	69.44%	30.56%	-		2	18.42%
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	59.30%	37.79%	2.91%		2	0.57%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-		4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-			-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	50.00%	50.00%		2	16.67%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	8.81%	3.14%	8.18%	5.66%	74.21%		4	7.55%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-			-
35												

4.3 Schedule 12a: report on asset condition (continued)

					Asset condition at start of planning period (percentage of units by grade)							
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	7.32%	14.63%	24.39%	53.66%		4	22.76%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.70%	3.73%	8.59%	11.31%	73.66%		4	9.21%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-			-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-			-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.01%	0.01%	1.85%	9.18%	88.95%		3	0.55%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	12.95%	87.05%		2	0.94%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	100.00%	-	-	-		3	100.00%
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	16.67%	27.78%	55.56%		4	2.78%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-			-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.84%	3.36%	11.25%	16.20%	67.35%		3	5.88%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-			-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.87%	5.74%	25.41%	40.57%	25.41%		4	15.16%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.39%	2.29%	6.69%	13.48%	76.15%		3	3.71%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.40%	2.68%	8.92%	10.77%	76.23%		3	7.27%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	16.67%	66.67%	16.67%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	14.17%	10.83%	28.33%	43.33%	3.33%		4	3.05%
55	LV	LV Line	LV OH Conductor	km	0.84%	1.52%	4.99%	8.36%	84.28%		4	3.79%
56	LV	LV Cable	LV UG Cable	km	0.01%	0.03%	0.33%	2.02%	97.61%		2	0.09%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	14.63%	8.07%	35.43%	36.01%	5.86%		2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	0.01%	24.92%	75.07%		3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	14.92%	16.13%	30.24%	33.47%	5.24%		3	26.61%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-		4	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	95.45%	4.55%		4	-
62	All	Load Control	Centralised plant	Lot	66.67%	16.67%	16.67%	-	-		4	33.33%
63	All	Load Control	Relays	No.	21.75%	5.72%	44.88%	24.95%	2.70%		3	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-			-

4.4 Schedule 12b: report on forecast capability

Company Name	Northpower
AMP Planning Period	1 April 2025 – 31 March 2035

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

12b(i): System Growth - Zone Substations

	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
		Not Required before DY2025	*Not Required before DY2025*	*Not Required before DY2025*	*before DY2025*	*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
9	Kensington Regional	63	Spring	50	N-1 switched	Security	0.0	Winter	33.2	N-1	Winter	33.2	34.8	N-1	Security	1	Zone substation transformer	Network upgrade	Implementation stage	1 - 3 years	Kensington Regional substation has breached N-1 security, we have managed this due to the strong 33kV interlinks with Maungatapere
10	Alexander Street	11	Winter	15	N-1	No constraint	4.4	Winter	4.2	N-1	Winter	3.9	4.4	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
11	Hikurangi	7	Winter	10	N-1	No constraint	2.8	Winter	2.3	N-1	Winter	1.6	2.5	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
12	Kamo	13	Spring	15	N-1	No constraint	2.0	Winter	0.9	N-1	Winter	0.0	1.0	N-1 switched	Security	8	Zone substation transformer	Undecided	Planning stage	> 3 years	It is expected that Kamo will breach its N-1 security within the next 10 years, we are currently exploring options to address this
13	Ngunguru	3	Winter	5	N	No constraint	2.0	Winter	1.8	N	Winter	1.6	2.0	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
14	Onerahi	7	Spring	15	N-1 switched	No constraint	8.2	Winter	7.8	N-1 switched	Winter	7.2	7.7	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
15	Parua Bay	4	Spring	5	N	No constraint	1.1	Winter	0.9	N	Winter	0.3	1.0	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
16	Tikipunga	17	Spring	20	N-1	No constraint	2.6	Winter	1.7	N-1	Winter	0.2	2.1	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
17	Bream Bay	6	Winter	10	N	Security	4.2	Winter	2.1	N-1	Winter	0.4	1.4	N-1	Security	1	Zone substation transformer	Network upgrade	Implementation stage	1 - 3 years	The load at bream bay has exceeding the capabilities of 11kV back feeding and does not meet our security of supply criteria, therefore
18	Ruakaka	8	Spring	10	N-1	No constraint	1.6	Winter	1.0	N-1	Winter	0.0	0.8	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
19	Maungatapere Regional	43	Winter	30	N-1 switched	Security	0.0	Winter	55.8	N-1	Winter	53.6	55.7	N-1	Security	1	Zone substation transformer	Network upgrade	Implementation stage	1 - 3 years	Maungatapere Regional substation has breached N-1 security, we have managed this due to the strong 33kV interlinks with
20	Maungatapere	6	Spring	8	N-1	No constraint	1.7	Winter	1.5	N-1	Winter	0.9	1.5	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
21	Maunu	4	Spring	10	N	No constraint	6.3	Winter	5.6	N	Winter	5.0	5.6	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
22	Kioreroa	9	Summer	20	N-1	No constraint	10.7	Winter	10.5	N-1	Winter	10.2	10.6	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
23	Poroti	3	Spring	5	N	No constraint	2.1	Winter	1.9	N	Winter	1.4	1.8	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
24	Whangarei South	11	Winter	10	N-1 switched	Security	0.0	Winter	0.0	N-1 switched	Winter	8.9	9.0	N-1	Security	1	Zone substation transformer	Network upgrade	Solution confirmed	> 3 years	Whangarei South has exceeded N-1, we have been managing this constraint with strong 11kV back feeds, plans are in place to
25	Dargaville	12	Winter	15	N-1	No constraint	3.0	Winter	2.8	N-1	Winter	2.1	2.9	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
26	Maungaturoto	6	Winter	8	N-1	No constraint	1.5	Winter	3.9	N-1	Winter	3.6	3.9	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
27	Ruawai	3	Winter	5	N	No constraint	2.1	Winter	2.1	N	Winter	1.9	2.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
28	Kaiwaka	3	Winter	5	N	No constraint	2.4	Winter	6.4	N	Winter	5.0	7.0	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
29	Mangawhai North	7	Winter	10	N	No constraint	3.5	Winter	5.9	N-1 switched	Winter	5.4	5.7	N-1 switched	Security	None	Subtransmission circuit	Network upgrade	Implementation stage	1 - 3 years	Currently 1 sub transmission circuit supplying the area. Second circuit is being constructed. Under transformer outage full
30	Mangawhai Central	2	Winter	15	N	No constraint	13.2	Winter	8.8	N-1 switched	Winter	8.0	8.6	N-1 switched	Security	None	Subtransmission circuit	Network upgrade	Implementation stage	1 - 3 years	Currently 1 sub transmission circuit supplying the area. Second circuit is being constructed. Under transformer outage full
31	Mareretu	3	Spring	5	N	No constraint	2.1	Winter	2.0	N	Winter	1.9	2.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	

† *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

4.5 Schedule 12c: report on forecast network demand

Company Name	**Northpower**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type

Number of connections

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
*Consumer types defined by EDB**						
Very large industrial		-	-	-		-
Commercial and Industrial	2	2	2	2	2	2
Mass market	867	876	884	893	902	911
Connections total	869	878	886	895	904	913

**include additional rows if needed*

Distributed generation

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Number of connections made in year	545	550	555	561	567	572
Capacity of distributed generation installed in year (MVA)	34	64	97	13	10	10

12c(ii): System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Maximum coincident system demand (MW)							
	GXP demand	145	148	124	125	126	127
plus	Distributed generation output at HV and above	5	5	31	34	34	34
	Maximum coincident system demand	150	153	155	159	160	161
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	150	153	155	159	160	161
Electricity volumes carried (GWh)							
	Electricity supplied from GXPs	759	595	358	375	381	387
less	Electricity exports to GXPs						
plus	Electricity supplied from distributed generation	28	208	454	461	461	461
less	Net electricity supplied to (from) other EDBs		-	-	-		-
	Electricity entering system for supply to ICPs	787	803	812	836	842	848
less	Total energy delivered to ICPs	744	758	768	790	796	801
	Losses	43	45	44	46	46	47
	Load factor	60%	60%	60%	60%	60%	60%
	Loss ratio	5.4%	5.5%	5.4%	5.5%	5.5%	5.5%

4.6 Schedule 12d: report forecast interruptions and duration

Company Name	**Northpower**
AMP Planning Period	
Network / Sub-network Name	**1 April 2025 – 31 March 2035**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	162.0	178.3	178.3	178.3	178.3	178.3
12	Class C (unplanned interruptions on the network)	93.0	98.0	98.0	98.0	98.0	98.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.72	0.79	0.79	0.79	0.79	0.79
15	Class C (unplanned interruptions on the network)	2.28	2.40	2.40	2.40	2.40	2.40

4.7 Schedule 14a: Mandatory explanatory notes on forecast information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2.
   This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between constant and nominal prices is based on the New Zealand Institute of Economic Research (NZIER) September 23 forecast with an increase of 3.5% through to FY27, after which it is based on an escalation of 2%.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Commentary on difference between nominal and constant price operational expenditure forecasts

The difference between constant and nominal prices is based on the New Zealand Institute of Economic Research (NZIER) September 23, with a 3.5% increase for Maintenance, 4% for Staff Payroll and 2% for other costs forecast through to FY27, after which it is based on an escalation of 2%.

Section 5:

Director Certification

5. Director Certification

We, Mark Trigg and Kerry Friend, being Directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

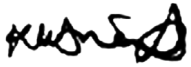
a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 11c, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Northpower Limited's corporate vision and strategy and are documented in retained records.

26 March 2025

Mark Trigg, Director Date



26 March 2025

Kerry Friend, Director Date