2025 Asset Management Plan

Update

31 March 2025

Contents

Introduction

CEO Message

Alpine Energy supplies an essential electricity supply to homes, farms, and businesses across South Canterbury. Decisions made 50 years ago still shape the way we deliver power today. Similarly, choices we make now will determine the future of our network for the next 50 years. How we do this will change over the next decade. Technology is advancing, energy use changing, and customer expectations growing. We are focused on building a stronger, smarter, and more responsive network to meet these challenges while managing the balance between cost and reliability over the short-term and the long-term.

Last year's AMP projected a significant increase in expenditure compared to historical levels. This was driven by asset replacement and renewal and system growth portfolios. We have refined the scope and cost of these portfolios following an increase to inspections and the amalgamation with our subsidiary that provides field services. As a result, the forecast cost of delivering our ARR programmes has increased by approximately 20%.

At the same time, some customer-initiated growth projects have been delayed due to the impact on customer plans from global and local economic demand for products and high wholesale electricity prices. While New Zealand's net-zero 2050 commitment remains, the mechanisms to enable this have changed too. This combination of factors has muted our industrial process heat conversions and growth, giving us more time to replace aging networks and upgrade substations.

Customers are telling us they expect more from us. We are responding by improving communication, explaining price changes clearly, and ensuring people understand the value of the services we provide. We are continuing to work closely with local councils, businesses, and communities to find practical, forward-thinking solutions that benefit everyone.

Looking beyond these near-term factors, we will be continuing to upgrade and maintain power lines and leveraging smarter technology to improve how we plan and operate the network and the business. These investments help prevent outages, reduce outage times for customers, and new ways to maintain security of supply. We look forward to working with our customers and stakeholders to make this transition a success.

Caroline Ovenstone

Chief Executive Officer

Purpose of AMP update

AMP Purpose Statement: Our AMP provides transparency to our stakeholders, customers, and our people on how we make investment decisions. It shows how our asset management practices support the decision-making process through the collection and use of data.

This 2025 AMP update is structured to meet the disclosure requirements set out by the Commerce Commission in the Electricity Distribution Information Disclosure Determination 2012 (ID Determination). Detailed explanations of our network and asset management planning approaches were provided in our full 2023 AMP – we have not repeated them here. Our strategic approach to managing and maintaining our network is unchanged from this 2023 AMP. In March 2024 we published our 2024 AMP update. Both AMPs are available on our website www.alpineenergy.co.nz.

This 2025 AMP update summarises material changes to our 2023 and 2024 AMPs, including those relating to our network development plans, asset lifecycle management, and digital investment.

Structure

- **Chapter 1** introduces our 2025 AMP update and provides context for the significant changes in our operating environment driving this AMP update. It also explains how the AMP aligns with our strategic objectives and the asset management planning we will undertake this year in preparation for our next full AMP in 2026.
- **Chapter 2** sets out the material changes from our 2024 AMPs, including our network development plans, asset lifecycle management and digital investment programme.
- **Chapter 3** is an update of our capital and operational expenditure forecasts for our network for the 10-year planning period and summarises major variances to our capital and operating expenditure from our 2024 AMP.
- Appendices include our updated Information Disclosure Schedules; forecast capital and operating expenditure, asset condition, forecast capacity and network demand, forecast interruptions and duration, explanatory notes on forecast information, and Directors' certification.

Information Disclosure requirements

Our 2025 AMP is prepared in accordance with the Commerce Commission's ID Determination. It covers the period 1 April 2025 to 31 March 2035 and addresses the following content requirements:

- Identify any material changes to the network development plans disclosed in the last AMP;
- Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP;

- 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; and
- Identify any changes to the asset management practices of the EDB.

We publicly disclose the AMP update prior to 1 April 2025 and include:

- the Report on Forecast Capital Expenditure in Schedule 11a;
- the Report on Forecast Operational Expenditure in Schedule 11b;
- the Report on Asset Condition in Schedule 12a;
- the Report on Forecast Capacity in Schedule 12b;
- the Report on Forecast Network Demand in Schedule 12c; and
- the Report on Forecast Interruptions and Duration in Schedule 12d

Chapter 1

Context

Our 2023 and 2024 AMPs reflected a shift away from 'just-in-time' investment to proactively strengthening and growing our network. The growing risk to network reliability and resilience from aging assets and climate hazards drove this shift. Electrification of the economy was a key factor too, with market and government initiatives driving customer plans and responses. As a result, both AMPs forecast a step-change from historic network investment levels.

The need for increased investment over the long-term due to these drivers remains. However, material changes in our operating environment in the past year have led to changes in our near-term expenditure forecasts and work programme.

- Macro-economic and government policy changes have seen a marked shift from a focus on electrification of energy, to energy security.
- There is a material gap between the level of investment required on our network, and what is allowed under the Commerce Commission's five-year Default Price-Quality Path (DPP4).
- Fully integrating our field services department within our operating model (following our 2023 amalgamation with NETcon) has provided better cost visibility, particularly for feeder and pole renewal programmes.

In response to our operating environment, we have developed two AMP investment scenarios:

- **Network Scenario:** this scenario is a revision of our 2024 AMP investment programme, designed to delivery on our objectives to:
    - Reduce network reliability and safety risk from aged and poor condition assets;
    - Increase capacity to meet forecast customer demand; and
    - Improve network resilience.

  Expenditure forecasts for the Network Scenario are in line with those in our 2024 AMP, requiring $458M over the ten-year period, and $245M in the next five years.
- **Constrained Scenario:** this scenario delivers expenditure forecasts in line with our DPP4 allowances for FY26 and FY27 by:
    - deferring investment in large growth projects until FY28;
    - reducing feeder upgrades and pole replacement programmes to historic replacement levels for the short term; and
    - managing network risk by increasing our inspection program and maintaining contingency in critical budgets to respond to high-risk defects and condition ratings.

Under this scenario $22M of network investment has been deferred to later years in the AMP. The ten-year forecasts within this scenario remain at $458, with $228M of investment planned for the next five years.

Our 2025 AMP expenditure forecasts are aligned with the 'Constrained' scenario while we assess funding options and build delivery capacity over the next two years. Chapter 2 provides more detail on how the impact of this scenario on our network plans.

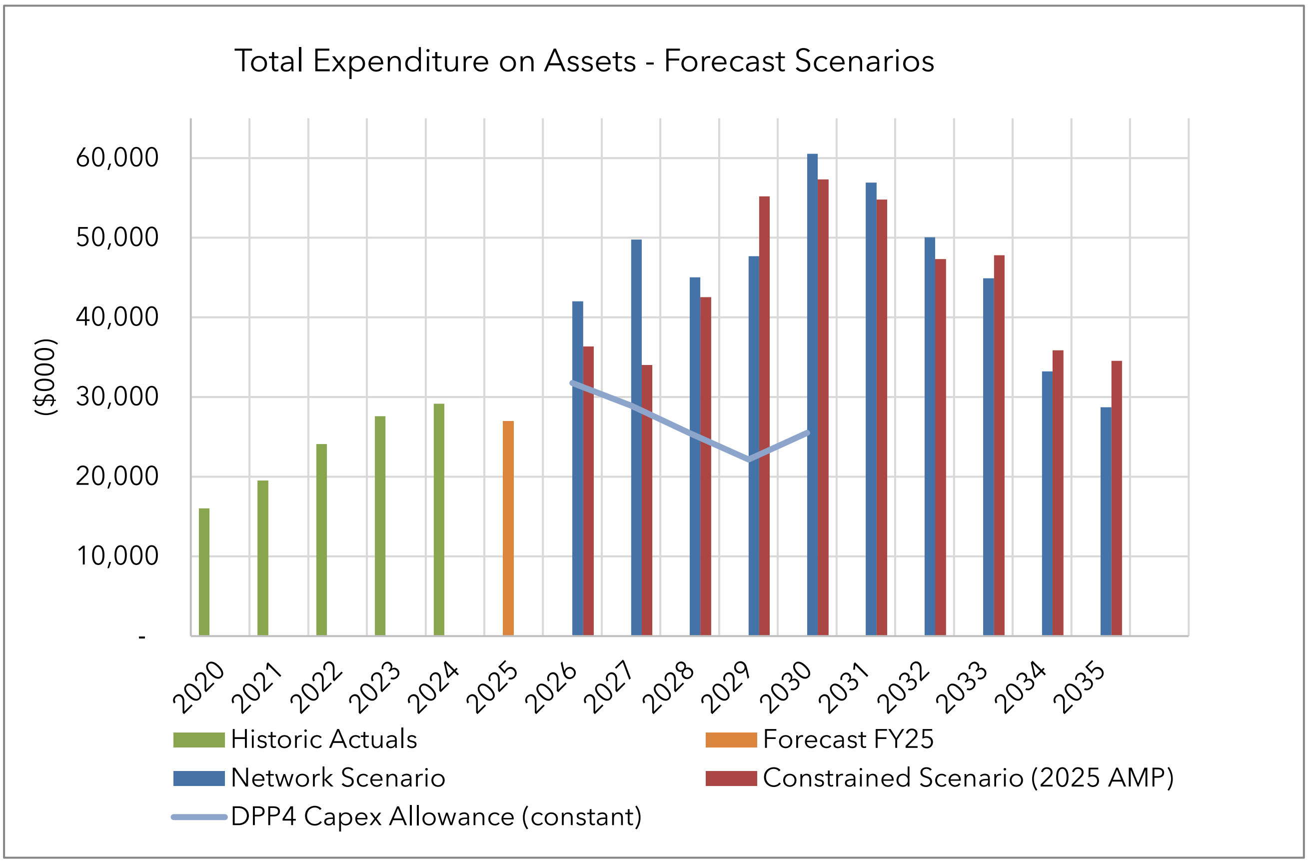

Figure 1: 2025 Asset Management Plan expenditure scenarios

Strategy alignment

Our purpose and strategic outcomes reflect the importance of our network to existing and future customers. A resilient and reliable power supply is critical to our region's success.

Empowering our vibrant and thriving communities now and for the future

Thriving communities	Electricity for all	Resilient and reliable electricity	Financial sustainability
Our people and communities are healthy, safe, and thriving	**All electricity users can access and use electricity they need**	**Our electricity supply is resilient and adaptive in the face of climate change**	**We have the capital and infrastructure to invest and deliver our strategy**
• Reliable electricity supports thriving families and businesses • Our people, communities and environment are healthy and safe	• Electricity is accessible, reliable, and affordable • Customers engage with us to make informed energy choices and access services that meet their needs	• Resilient and reliable electricity infrastructure and services span the needs of localities and generations • Our network adapts to, and stands strong in, the face of climate change	• We have the capital to invest in the future to deliver on our strategy and asset management plan (right place, right time, right solution)

The alignment between our AMP and out long-term strategic objectives are summarised below.

Thriving communities, resilient and reliable electricity

Security of supply and network safety are primary concerns for our customers. By using a risk-based approach to both our asset lifecycle and growth planning we are targeting our investment within this AMP at:

- Aged, poor condition, and near capacity cables on critical parts of our network are a significant risk to network resilience; and

- Climate-change related weather and seismic risk. We have prioritised investment to improve resilience in the highest risk, and most critical locations.

Over the next two years we will scale up our delivery capacity and improve our asset intelligence through our digital investment programme. This will enable us to increase our renewal programmes efficiently to begin tackling our aging asset profile in earnest and strengthening our network.

Electricity for all

Increasing network capacity in areas of forecast growth is part of our strategic objective that all electricity users can access and use the electricity they need. Our network roadmaps, which support our Network Delivery Plans have been critical to refining our understanding of what growth is needed, when and where. We are also exploring when that capacity can be met by other sources, such as demand flexibility or alternative network solutions.

In the past year we have seen a softening of demand in the near-term, particularly from industrial and commercial customers, driven by economic conditions. Our longer-term demand forecasts still indicate significant growth as major industrial customers pursue decarbonisation and growth plans. Over the next year we will work with customers to refine our understanding of when and where capacity is required, to mitigate the risk that our Constrained Scenario may present for providing capacity to meet customer demand beyond our forecasts.

Financial Sustainability

By adopting the Constrained Scenario, we are delivering on our objective of having the capital and infrastructure to deliver on our strategy (right place, right time, right solution).

Looking ahead to 2026 AMP

Work has already begun on our next full asset management plan which we will publish before 1 April 2026.

A focus will be our 2026 Asset Management Maturity (AMMAT) improvement programme. This will include:

- Increased asset inspection programme to gain better condition data about our assets.
- Aligning our asset management practices with the best industry practice to assess the health of these assets and associated risks they present.
- Scrutinising our demand and consumer connections forecasting methodology and the inputs and assumptions that contribute to these forecasts.
- Quantifying risks associated with the health of our assets and forecast constraints on these assets using mechanisms such as VoLL (Value of Loss Load).
- Risk-based assessments for prioritising the network investment required to maintain financial viability and affordability for our customers.
- Standardised practices to efficiently deliver planned work to ensure optimum return on our investment for our customers and shareholders.

Chapter 2

2025 AMP – Constrained Scenario

The capex allowances provided by the Commerce Commission's default price path (based on 2024 AMP forecasts) were lower than our AMP24 forecasts. We have adjusted projected spend for the next two years to align with these allowances. This allows time to explore alternative funding, reassess risk profiles, and optimise our delivery capacity. Our Constrained Scenario aligns with our capex allowances in the short term. Longer term, we expect network investment to increase significantly across the life of this AMP to ensure network resilience. Our forecasts from 2028-2035 reflect this.

Material Changes – Growth

We continue to review and seek improvements to our network development plans so our investments are efficient. A decrease in customer activity due to economic conditions, and a cooling of some development plans for larger electrification and growth projects has led to a reduction in our demand forecast, particularly in Washdyke and Timaru. Our customer composition is such that decisions by a relatively small number of customers can make a relatively large difference to our forecasts. Our response to this is to engage regularly.

In this context, our 2025 AMP reflects material changes to our growth plans due to three key drivers:

- Uncertainty of demand – Customer driven growth projects included in our 2024 AMP have not progressed as anticipated. In a constrained funding context, it would not be prudent to proceed with planning, or proactively invest to increase capacity in anticipation of demand.
- Funding constraints – to deliver an affordable works programme within our DPP4 capex allowances, growth projects have been deferred during the first two years of the AMP.
- Risk-based approach for project prioritisation – projects delivering network risk reduction, and increased resilience have been prioritised.

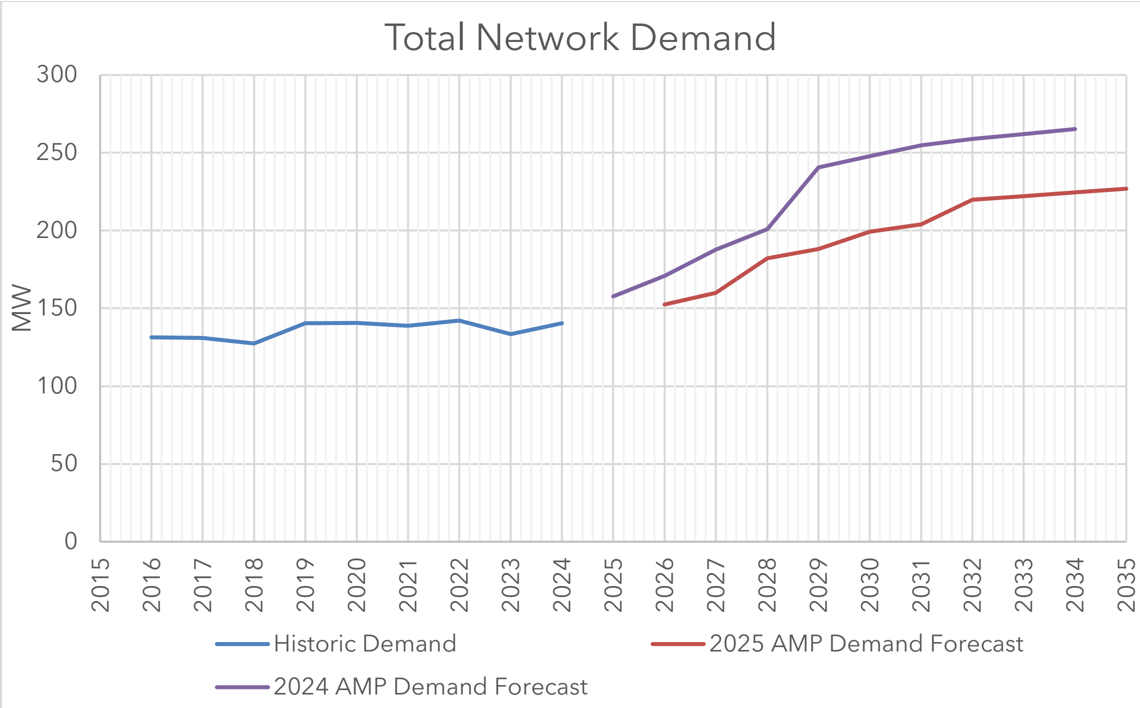

Figure 2. Total Network Demand

Project	Change	Driver	Cost	Timing
Washdyke system growth projects				
Build new Washdyke 33kV substation	Deferred project	Capacity provided through completion of Washdyke Switching Station in 2026. Network reconfiguration provides enough capacity to meet refined demand forecasts	$10M	2028-2029 (2024 AMP: 2025 – 2026)
Washdyke Cable Ring	Expenditure reduction and deferred delivery	Uncertainty of demand.	$20M (2024 AMP: $26M)	2026-35

Project	Change	Driver	Cost	Timing
Timaru system growth projects				
Timaru sub-transmission circuits	Project rescoped	Uncertainty of demand. Project now focused on critical assets (Grasmere sub-transmission cable upgrades) to increase capacity while replacing aged and poor condition assets.	$8.5M (2025 AMP: $16.7M)	2028-32 (2024 AMP: 2026 – 2032)
New Port Switching Station	Project delayed, and repriced	Uncertainty of demand.	$15M (2024 AMP: 5M)	2031-33 (2024 AMP: 2027-2029)
2024 AMP projects – removed from AMP				
New Timaru CBD switching station	Deferred beyond 10-year AMP	Uncertainty of demand	$0 (2024 AMP: $5.4M)	Beyond 2035 (2024 AMP:2029-2030)
Timaru CBD feeder upgrades	Deferred beyond 10-year AMP	Uncertainty of demand.	$0 (2024 AMP: $6M)	Beyond 2035 (2024 AMP: 2025-2034)

Risk mitigation for Constrained Scenario:

- We already have work underway to increase capacity at Washdyke with a new switching station nearing completion. Through network reconfiguration we will have sufficient capacity to connect known customers in the near-term. Unforeseen customer activity will be addressed though the funding mechanisms available through the regulatory regime (reopeners).
- The next phase of our Washdyke Roadmap, the construction of a new substation and the completion of the Washdyke Cable Ring, will be reviewed during 2026, based on up-to-date customer information. We will consider reopener applications for these significant growth projects following this review.
- The delivery of additional capacity to both Timaru and Washdyke is dependent on the Timaru GXP upgrade to 33kV (Transpower project). New timelines for these projects still align with the completion of the GXP upgrade.

Material Changes – Asset Lifecycle Management

Our Asset Lifecycle Management plans have not changed materially for this AMP. However, to align with our Constrained Scenario we have reduced expenditure forecasts in 2026 and 2027, compared with our 2024 AMP forecasts.

Change	Explanation	Cost	Timing
Feeder and Pole Renewal Programme			
Maintain current feeder and pole renewal programme for 2026 and 2027, deferring our 2024 plans to increase pole replacements from 600 to 850 per annum.	6,170 wooden poles have outlived their CBARM life of 47 years, and 633 concrete poles have exceeded a 68-year lifespan. The need for a robust pole replacement plan is clear and urgent. 9,426 poles on our network have not been inspected in the past ten years, and 2,465 of these poles have already exceeded their CBARM lifespan. Increasing our feeder and pole renewal programme over time will help reduce the risk currently sitting with this asset fleet and improve network resilience and service quality over time. While we build capacity to deliver an increased feeder and pole renewal programme, we will continue to replace 600 poles per annum, prioritising poles with identified defects. As we work through the backlog of aged pole inspections over the next two years, we will review and reprioritise replacements based on critical safety and network reliability risks.	2026 and 2027: $8.3M p/a Increasing to $15M p/a by 2030 $130M investment over 10 years (2024 AMP: $82M over 10 years)	10-year programme
Increased cost of overhead line renewal	We now have greater visibility over the true cost of overhead line renewal following our amalgamation with our field services provider.	Increase from $10k to $15k per pole	
Underground substation renewal			
Reduction in the number of underground substations relocated above-ground, from 5 to 3.	The underground location of the substations introduces specific risks such as arc flash incidents, electrocution hazards, and delayed emergency response. To reduce our capex forecasts in 2026 and 2027 we have smoothed out underground substation replacement programme over eight years of our AMP and revised our project pricing.	$10M (2024 AMP: $12.6M)	8-year programme (2024 AMP: 6-year programme

Risk mitigation for Constrained Scenario:

- In line with our Asset Management Policy and our 2024 AMP, we continue to use Condition-Based Asset Risk Management to prioritise our asset lifecycle management programmes.
- We have increased our network operating expenditure for Routine Maintenance and Inspections to mitigate the risks associated with asset degradation. This enables us to detect and mitigate potential failures before they occur, minimising faults, unplanned outages, and safety hazards.

Material Changes – Digital Investment

The projects and deliverables within this programme have not materially changed from our 2024 AMP, however cyber security costs have increased, and we have consolidated some projects. We have a greater understanding of how critical the digital architecture and capabilities are to achieving our asset management objectives. As a result, we have consolidated some projects to ensure our deliverables across the value chain align.

Our digital investment programme is driven by:

- Replacement or strengthening of legacy systems which are out of support and present single points of failure and security risks.
- Implementation of a revised operating model which will transform core value chain processes and responsibilities by eliminating manual effort and rework, improving the quality of our asset data to better inform investment analysis, and streamlining end-to-end processes.
- Continued focus on cybersecurity due to the increasing cyber risk landscape. Our forecasts include enhanced system security measures to reduce network vulnerability.

Our primary focus for the initial years of this AMP is to replace or strengthen core systems, including our Enterprise Resource Planning (ERP) system and GIS platform. We have consolidated the ERP and an Enterprise Asset Management (EAM) system implementation into a single, integrated solution. This approach will improve our value chain processes earlier, improving efficiency and alignment across our operations.

Project	Change	Driver	Cost	Timing
Digital Investment Programme				
Operating model transformation, underpinned by target technology and data architecture programme	Consolidation of core technical architecture programmes to support and align with operating model transformation to drive an efficient core value chain.	We have multiple legacy systems that are no longer fit for purpose and prevent us from leveraging technology to drive efficiency, innovation and electricity-specific systems to respond to evolving demand.	\$16.7M (2024 AMP: 16.6M)	5-year programme

Project	Change	Driver	Cost	Timing
Cyber Security	Reforecast expenditure	In 2024 we completed the implementation of our Security Operations Centre, in partnership with Vector, to provide EDB focussed detection and response capabilities. We now have a clear understanding of ongoing costs to maintain and enhance our cyber security posture against an evolving change landscape, extending that to new exposure points as we implement new systems. This changed forecast includes the improvement of our risk profile in our Operational Technology environment and security assurance and testing of new systems.	$7.8M (2024 AMP: $5.3M)	10-year programme

Asset Management Maturity

We are continuing our asset management maturity journey with the improvement initiatives identified in our full 2023 AMP. Our focus in preparing this AMP update has been on revising our planned network projects and programmes within a constrained financial. This has not resulted in any changes to the asset management practices that would affect the Report on Asset Management Maturity disclosure. Our 2026 AMP will include an independent assessment of our asset management maturity.

Chapter Three

Expenditure forecast overview

This chapter details our capex and opex forecasts for the next 10-year planning period. It provides a high-level comparison with our forecasts included in the 2024 AMP. It highlights how our investment plan has been constrained for the first two years of the AMP before returning to previous forecasts to deliver the growth and build the resilience our network will need in the future.

Material changes from our 2024 AMP capex and opex forecasts are discussed.

Forecasts are presented in the 2025 prices (constant prices) and reflect those included in the Report on Forecast Capital Expenditure (Appendix 1 – Schedule 11a) and Report on Operating Expenditure (Appendix 2 – Schedule 11b). The forecast expenditure is based on the best information available at the time of publishing our AMP Update.

Network Expenditure

Network capex

Network capex includes expenditure across the following categories:

- System growth
- Asset renewal and replacement
- Consumer connections
- Asset relocations
- Reliability, safety, and environment.

We have forecast a total network capex programme of $432 million over the 10-year planning period, a $17.7 million reduction on our 2024 AMP.

At an aggregated level, the main drivers for the change in capital expenditure profile are:

- Constrained expenditure resulting from our DPP4 capex allowance being set lower than our 2024 AMP forecasts. To ensure financial sustainability we have deferred expenditure from 2026 and 2027.
- A decrease in growth expenditure ($25M less than our 2024 AMP), driven by a decline in forecast demand in the near-term allowing us to defer some large growth projects beyond the life of the AMP.
- An $8M increase in our renewal, replacement and reliability (ARR and RSE) reflects the increase costs to deliver feeder and pole renewals.

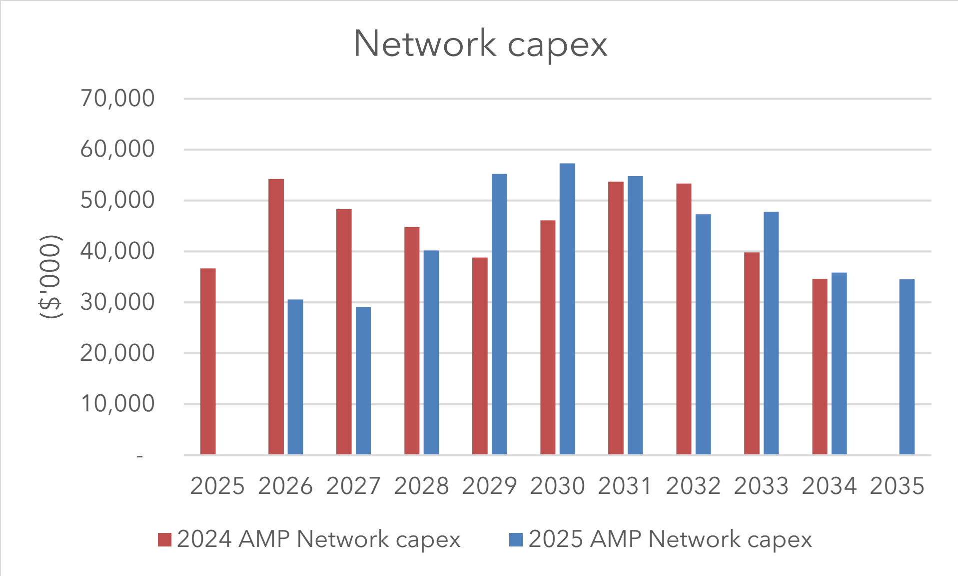

Figure 3: Forecast expenditure on network assets

Network opex

Network opex includes expenditure across the following categories:

- Service interruptions and emergencies
- Vegetation management
- Routine and corrective maintenance and inspections
- Asset renewal and replacement

We have forecast a total network opex programme of $73 million over the 10-year planning period. Our forecasts have not changed materially since our 2024 AMP. To reduce network reliability and safety risk within our constrained scenario, we have increased our 2026 Routine and Corrective Maintenance and Inspections budget by $500K.

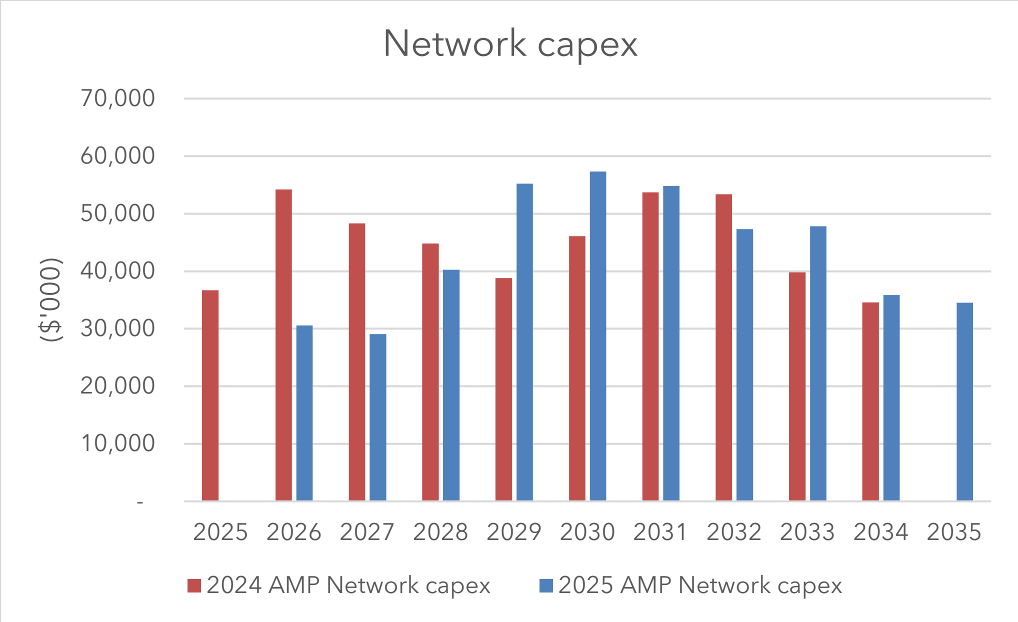

Figure 4: Forecast network operating expenses.

Non-Network Expenditure

Non-network capex

Our 2024 AMP includes $27.4million of non-network capex. This is an increase of $18 million from our 2024 AMP. This variance reflects the impact of our amalgamation with our field services provider, and the additional vehicle fleet expenditure forecast as a result.

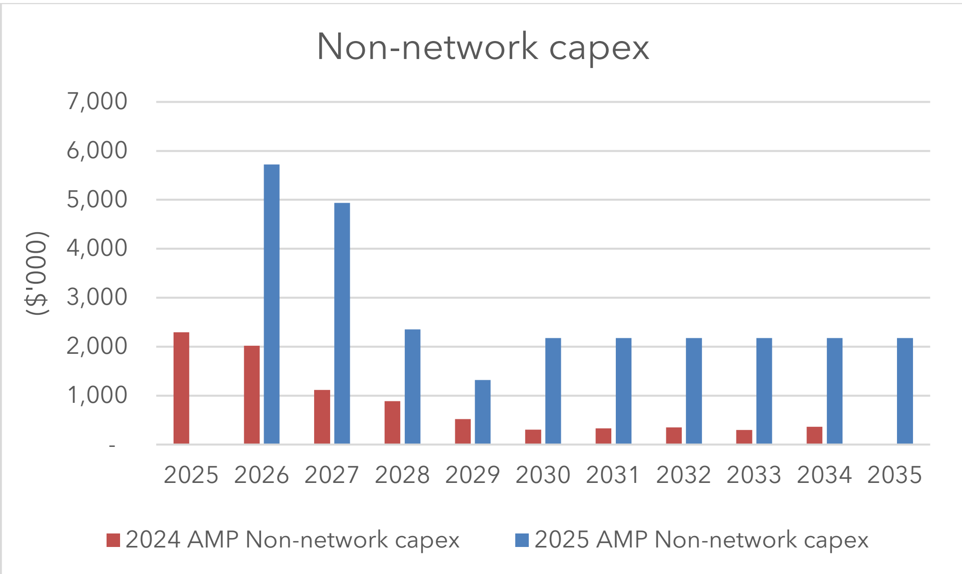

Figure 5: Forecast expenditure on non-network assets

Non-network opex

Non-network opex includes expenditure across two categories:

- System operations and network support

- Business support

We have forecast total non-network operating costs of $272 million over the 10-year planning period, a decrease of $29M from our 2024 AMP. Our opex forecasts include an efficiency factor as we have now fully integrated field services into our value chain.

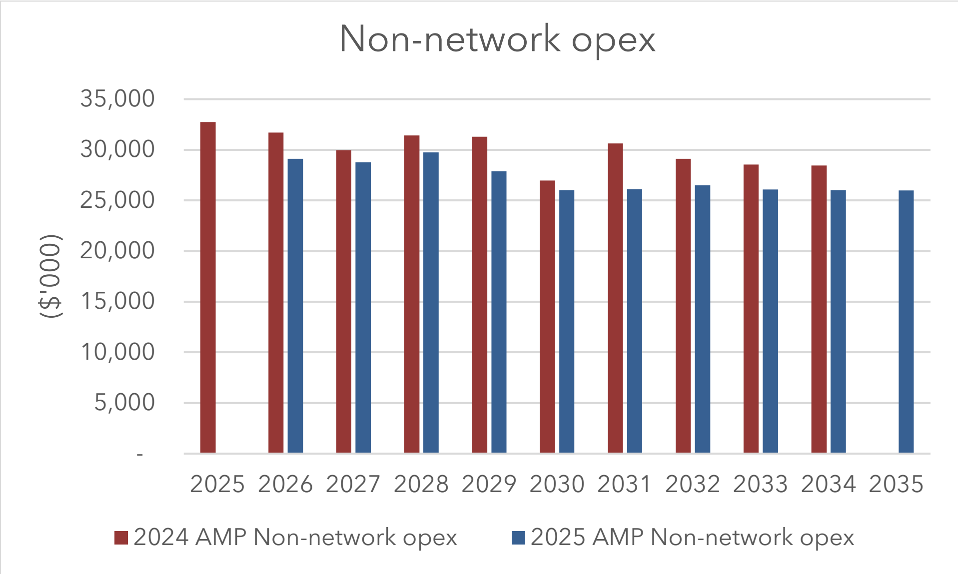

Figure 5: Forecast expenditure on non-network opex

Appendix 1

Schedule 11a. Report on forecast capital expenditure

Company Name	**Alpine Energy Limited**
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.

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			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8			**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	7,310	4,688	5,440	5,742	8,622	8,159	8,879	9,071	6,943	7,089	7,234
11		System growth	8,840	3,651	4,233	13,628	17,886	14,372	21,719	18,267	23,103	9,831	2,303
12		Asset replacement and renewal	16,968	16,628	17,097	18,910	24,716	30,575	27,259	24,949	23,900	24,071	29,636
13		Asset relocations	250	750	817	1,824	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	-	1,137	584	596	1,354	948	2,632	988	1,009	1,030	1,145
16		Legislative and regulatory	800	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	2,535	3,714	1,515	1,241	6,175	8,231	331	338	345	341	1,338
18		**Total reliability, safety and environment**	3,335	4,851	2,099	1,837	7,529	9,178	2,962	1,325	1,353	1,370	2,484
19		**Expenditure on network assets**	36,703	30,568	29,686	41,941	58,753	62,284	60,820	53,612	55,299	42,361	41,656
20		**Expenditure on non-network assets**	2,292	5,809	5,044	2,408	1,405	2,362	2,412	2,462	2,514	2,567	2,621
21		**Expenditure on assets**	38,995	36,378	34,730	44,349	60,158	64,646	63,231	56,075	57,813	44,927	44,277
22													
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	6,625	3,636	4,170	4,013	5,907	6,031	5,048	5,154	4,858	4,960	5,064
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	32,370	32,742	30,560	40,336	54,251	58,615	58,183	50,920	52,955	39,968	39,213
28													
29		Assets commissioned	31,284	29,102	27,784	35,479	48,127	51,717	50,585	44,860	46,250	35,942	35,421

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				**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
32			**$000 (in constant prices)**										
33		Consumer connection	7,310	4,688	5,328	5,508	8,101	7,508	8,003	8,008	6,003	6,003	6,000
34		System growth	8,840	3,651	4,146	13,073	16,805	13,225	19,575	16,125	19,975	8,325	1,910
35		Asset replacement and renewal	16,968	16,628	16,745	18,140	23,222	28,136	24,569	22,024	20,664	20,384	24,580
36		Asset relocations	250	750	800	1,750	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	-	1,137	572	572	1,272	872	2,372	872	872	872	950
39		Legislative and regulatory	800	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	2,535	3,714	1,484	1,190	5,802	7,574	298	298	298	288	1,110
41		**Total reliability, safety and environment**	3,335	4,851	2,056	1,762	7,074	8,446	2,670	1,170	1,170	1,160	2,060
42		**Expenditure on network assets**	36,703	30,568	29,075	40,233	55,202	57,316	54,817	47,327	47,812	35,872	34,550
43		Expenditure on non-network assets	2,292	5,809	4,940	2,310	1,320	2,174	2,174	2,174	2,174	2,174	2,174
44		**Expenditure on assets**	38,995	36,378	34,015	42,543	56,522	59,489	56,991	49,501	49,986	38,046	36,724
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										
50		Research and development											
52													

Company Name	Alpine Energy Limited
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

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*
54		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	-	112	234	521	651	876	1,063	940	1,086	1,234
57	System growth	-	-	87	555	1,081	1,146	2,144	2,141	3,128	1,506	393
58	Asset replacement and renewal	-	-	352	770	1,494	2,439	2,690	2,925	3,236	3,687	5,056
59	Asset relocations	-	-	17	74	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	-	-	12	24	82	76	260	116	137	158	195
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	-	31	51	373	657	33	40	47	52	228
64	**Total reliability, safety and environment**	-	-	43	75	455	732	292	155	183	210	424
65	**Expenditure on network assets**	-	-	611	1,708	3,551	4,968	6,003	6,285	7,487	6,489	7,106
66	Expenditure on non-network assets	-	-	104	98	85	188	238	289	340	393	447
67	**Expenditure on assets**	-	-	714	1,806	3,636	5,157	6,241	6,574	7,827	6,882	7,553

68

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

70 *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*

71

72

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
74	**11a(ii): Consumer Connection**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	Large Industrial	1,120	1,120	1,600	2,500	3,000	3,000
	Commercial	960	640	800	1,000	1,500	1,500
	Subdivision	1,200	800	800	1,000	1,000	1,000
	Irrigation	320	200	200	100	100	100
	Residential	1,200	720	720	900	900	900
77	Large Distributed Generation	1,500	1,200	1,200	-	1,000	1,000
78	HV Alterations	320	-	-		600	-
79	LV Alterations	40	8	8	8	1	8
80	Switchgear	650					
81	*include additional rows if needed*						
82	**Consumer connection expenditure**	7,310	4,688	5,328	5,508	8,101	7,508
83	*less* Capital contributions funding consumer connection	6,625	3,636	4,170	4,013	5,907	6,031
84	**Consumer connection less capital contributions**	685	1,052	1,158	1,495	2,193	1,477
85	**11a(iii): System Growth**						
86	Subtransmission	-	-	-	-	-	3,000
87	Zone substations	3,780	30	780	8,420	11,630	3,900
88	Distribution and LV lines	-	400	600	610	250	-
89	Distribution and LV cables	2,210	2,049	1,879	2,749	3,881	5,281
90	Distribution substations and transformers	2,300	472	72	422	72	72
91	Distribution switchgear	300	-	-	72	72	72
92	Other network assets	250	700	815	800	900	900
93	**System growth expenditure**	8,840	3,651	4,146	13,073	16,805	13,225
94	*less* Capital contributions funding system growth						
95	**System growth less capital contributions**	8,840	3,651	4,146	13,073	16,805	13,225

96

Company Name	**Alpine Energy Limited**
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		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
98		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
99	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
100	Subtransmission	-	-	-	-	-	-
101	Zone substations	220	243	173	638	302	6,520
102	Distribution and LV lines	8,398	4,568	2,468	1,958	3,726	4,726
103	Distribution and LV cables	1,690	634	484	674	1,069	964
104	Distribution substations and transformers	5,465	9,193	11,660	12,860	16,029	15,600
105	Distribution switchgear	1,195	1,489	959	1,009	2,096	326
106	Other network assets	-	500	1,000	1,000	-	-
107	**Asset replacement and renewal expenditure**	16,968	16,628	16,745	18,140	23,222	28,136
108	*less* Capital contributions funding asset replacement and renewal						
109	**Asset replacement and renewal less capital contributions**	16,968	16,628	16,745	18,140	23,222	28,136
110							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
112		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
113	**11a(v): Asset Relocations**						
114	*Project or programme**	**$000 (in constant prices)**					
115	Distribution Cable	50	750	800	1,750		
116	Distribution Transformer	200					
117							
118							
119							
120	**include additional rows if needed*						
121	All other project or programmes - asset relocations						
122	**Asset relocations expenditure**	250	750	800	1,750	-	-
123	*less* Capital contributions funding asset relocations						
124	**Asset relocations less capital contributions**	250	750	800	1,750	-	-
125							

Company Name	Alpine Energy Limited
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.

11a(vi): Quality of Supply

sch ref		Project or programme*	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
129			$000 (in constant prices)					
130		Communication	-	100	100	100	100	100
131		Distribution Switchgear		195	-	-	-	-
132		Distribution Transformer		70	-	-	-	-
133		Load and Voltage Control		772	472	472	1,172	772
134				-	-	-	-	-
135		*include additional rows if needed						
136		All other projects or programmes - quality of supply						
137		**Quality of supply expenditure**	-	1,137	572	572	1,272	872
138	less	Capital contributions funding quality of supply						
139		**Quality of supply less capital contributions**	-	1,137	572	572	1,272	872

11a(vii): Legislative and Regulatory

sch ref		Project or programme*	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
144			$000 (in constant prices)					
145		Distribution Line	800	-	-	-	-	-
146								
147								
148								
149								
150		*include additional rows if needed						
151		All other projects or programmes - legislative and regulatory						
152		**Legislative and regulatory expenditure**	800	-	-	-	-	-
153	less	Capital contributions funding legislative and regulatory						
154		**Legislative and regulatory less capital contributions**	800	-	-	-	-	-

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

sch ref		Project or programme*	Current Year CY 31 Mar 25	CY+1 31 Mar 26	CY+2 31 Mar 27	CY+3 31 Mar 28	CY+4 31 Mar 29	CY+5 31 Mar 30
158			$000 (in constant prices)					
159		Communication	200	170	170	170	-	-
160		Distribution Cable	750	12	12	12	312	12
		Distribution Line	-	100	-	-	-	-
		Distribution Substations	335	580	-	-	-	-
		Distribution Switchgear	710	806	156	506	156	806
		Load Control	400	-	1,100	456	1,626	126
		Protection	-	650	-	-	150	-
		SCADA and Communications	140	36	36	36	48	120
		Substation	-	-	-	-	3,500	3,500
		Subtransmission Cable	-	-	-	-	-	-
161		Subtransmission Line	-	-	-	-	-	3,000
162		Switchgear	-	1,000	-	-	-	-
163		Zone Substation Transformer	-	360	10	10	10	10
164		*include additional rows if needed						
165		All other projects or programmes - other reliability, safety and environment						
166		**Other reliability, safety and environment expenditure**	2,535	3,714	1,484	1,190	5,802	7,574
167	less	Capital contributions funding other reliability, safety and environment						
168		**Other reliability, safety and environment less capital contributions**	2,535	3,714	1,484	1,190	5,802	7,574

Company Name	**Alpine Energy Limited**
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		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
171		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	Fleet		3,494	1,190	980	70	690
176	Digital		496	300	180	300	534
177	Property		1,100	3,000	700	500	500
178	Plant and Equipment	350	620	450	450	450	450
179	Cyber security	110					
180	**include additional rows if needed*						
181	All other projects or programmes - routine expenditure	482					
182	**Routine expenditure**	942	5,709	4,940	2,310	1,320	2,174
183	**Atypical expenditure**						
184	*Project or programme**						
185	Transformer Bund		100				
186	Property	1,000					
187	Branding	260					
188							
189							
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure	90					
192	**Atypical expenditure**	1,350	100	-	-	-	-
193							
194	**Expenditure on non-network assets**	2,292	5,809	4,940	2,310	1,320	2,174

Appendix 2

Schedule 11b. Report on forecast operating expenditure

Company Name	**Alpine Energy Limited**
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*
8			**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		2,528	2,181	2,242	2,316	2,392	2,469	2,696	2,753	2,810	2,869	2,930
11	Vegetation management		1,525	1,000	1,030	1,061	1,093	1,126	1,126	1,126	1,126	1,126	1,126
12	Routine and corrective maintenance and inspection		3,488	4,392	3,986	4,100	4,225	4,356	4,356	4,356	4,356	4,356	4,356
13	Asset replacement and renewal		221	25	50	50	50	50	50	50	50	50	50
14	**Network Opex**		7,763	7,598	7,308	7,527	7,760	8,001	8,228	8,285	8,342	8,401	8,462
15	System operations and network support		5,645	6,307	6,717	6,876	6,985	7,132	7,294	7,460	7,593	7,748	7,886
16	Business support		17,946	22,802	22,642	24,129	22,697	21,146	21,684	22,545	22,577	22,977	23,452
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**		23,591	29,109	29,358	31,005	29,682	28,277	28,978	30,004	30,170	30,724	31,338
19	**Operational expenditure**		31,355	36,707	36,666	38,532	37,442	36,278	37,206	38,289	38,512	39,125	39,800
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21													
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		2,528	2,181	2,196	2,222	2,247	2,272	2,430	2,430	2,430	2,430	2,430
24	Vegetation management		1,525	1,000	1,009	1,018	1,027	1,036	1,015	994	974	954	934
25	Routine and corrective maintenance and inspection		3,488	4,392	3,904	3,933	3,970	4,009	3,926	3,845	3,766	3,689	3,613
26	Asset replacement and renewal		221	25	49	48	47	46	45	44	43	42	41
27	**Network Opex**		7,763	7,598	7,158	7,221	7,291	7,363	7,416	7,314	7,213	7,114	7,018
28	System operations and network support		5,645	6,307	6,578	6,596	6,563	6,563	6,574	6,585	6,565	6,561	6,541
29	Business support		17,946	22,802	22,176	23,147	21,325	19,459	19,544	19,902	19,520	19,457	19,451
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**		23,591	29,109	28,754	29,743	27,888	26,022	26,118	26,487	26,085	26,018	25,992
32	**Operational expenditure**		31,354	36,707	35,912	36,964	35,179	33,384	33,534	33,801	33,298	33,132	33,010
33	**Subcomponents of operational expenditure (where known)**												
35													
36	Energy efficiency and demand side management, reduction of energy losses												
37	Direct billing*												
38	Research and Development												
39	Insurance		649	703	718	733	748	764	780	797	814	831	848
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
42													
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44			**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	-	46	94	145	197	266	323	380	439	500
47	Vegetation management		-	-	21	43	66	90	111	132	152	172	192
48	Routine and corrective maintenance and inspection		-	-	82	167	255	347	430	511	590	667	743
49	Asset replacement and renewal		-	-	1	2	3	4	5	6	7	8	9
50	**Network Opex**		-	-	150	306	469	638	812	971	1,129	1,287	1,444
51	System operations and network support		-	-	138	280	422	569	720	875	1,028	1,187	1,345
52	Business support		-	-	466	982	1,372	1,687	2,140	2,643	3,057	3,519	4,001
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	604	1,262	1,794	2,256	2,860	3,518	4,085	4,706	5,346
55	**Operational expenditure**		-	-	754	1,569	2,263	2,894	3,672	4,489	5,214	5,993	6,790
56													

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.*

Appendix 3

Schedule 12a. Report on asset condition

Company Name	**Alpine Energy Limited**
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												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**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**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.06%	31.83%	33.08%	35.03%		3	1.10%
11	All	Overhead Line	Wood poles	No.	16.55%	8.99%	7.52%	22.15%	44.79%		3	1.50%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-		N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	16.32%	18.18%	36.90%	28.60%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-		N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0.12%	0.31%	6.52%	93.05%		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-		N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-		N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	2.13%	83.27%	14.61%		3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-		N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-		N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-		N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-		N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-		N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	16.00%	-	-	32.00%	52.00%		3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-		N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	5.81%	9.30%	23.26%	10.47%	51.16%		4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	21.57%	15.69%	19.61%	1.96%	41.18%		3	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	4.27%	6.84%	16.24%	5.98%	66.67%		3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-		N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-		N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	50.00%	50.00%		4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	3.76%	-	11.27%	25.82%	59.15%		3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	6.78%	93.22%		3	-
35												

Company Name	**Alpine Energy Limited**
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												
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38	**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**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	11.11%	3.70%	22.22%	62.96%		3	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.57%	41.17%	17.59%	15.89%	22.80%		3	2.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	100.00%	-	-	-		3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.27%	0.95%	1.09%	15.16%	82.52%		3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	2.20%	82.73%	15.06%		3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	11.43%	45.71%	42.86%		3	5.70%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	4.85%	-	14.55%	33.33%	47.27%		3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	15.48%	5.35%	5.38%	25.82%	47.96%		3	5.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1.41%	2.82%	1.41%	2.82%	91.55%		3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.73%	14.32%	25.73%	12.45%	43.78%		3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.37%	30.35%	30.11%	24.03%	14.15%		3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.54%	17.25%	24.31%	32.44%	25.47%		3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	67.65%	32.35%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	0.37%	13.19%	60.55%	21.50%	4.39%		3	2.00%
56	LV	LV Cable	LV UG Cable	km	0.26%	0.57%	6.80%	58.42%	33.95%		3	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km							N/A	
58	LV	Connections	OH/UG consumer service connections	No.							N/A	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2.00%	3.12%	13.59%	71.94%	9.35%		3	3.10%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1.95%	0.28%	23.68%	28.13%	45.96%		3	5.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	21.43%	-	32.14%	46.43%		3	-
62	All	Load Control	Centralised plant	Lot	2.04%	-	40.82%	36.73%	20.41%		3	16.00%
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Appendix 4

Schedule 12b. Report on forecast capacity

		Company Name	Alpine Energy Limited
		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

7 **12b(i): System Growth - Zone Substations**

sch ref	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
8			*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*	
9	Albury (ABY)	3.31	Winter	6.92	N	No constraint	3.61	Winter	2.95	N	Winter	2.18	2.26	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
10	Old Man Rage (OMR)	0.40	Summer	1.40	N	No constraint	1.00	Summer	0.91	N	Summer	0.81	0.89	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
11	Bells Pond (BPD)	16.59	Summer	20.00	N-1	No constraint	3.41	Summer	39.87	N	Summer	35.58	39.14	N	Security	5	Zone substation transformer	Divert load to alternative substation	No active planning	> 3 years	Network upgrades to switch/ transfer part of the load to other GXP/ Zone Sub by building HV feeder ties as a temporary solution. N capacity at zone sub transformer level is 60 MVA
12	Clandeboye 1 (CD1)	14.07	Autumn	20.00	N-1	No constraint	5.93	Summer	5.23	N	Summer	0.00	24.13	N	Capacity	2	Zone substation transformer	Network upgrade	Planning stage	Not applicable	New decarbonization loads at Clandeboye will be connected onto a new zone substation (CD3) from 2027, then load on CD1 will be within the existing capacity and security limits New zone substation CD3 (2x120MVA) to be established by 2027. Driven by Fonterra Clandeboye decarbonization plan
13	Clandeboye 2 (CD2)	19.95	Summer	23.69	N-1	No constraint	3.74	Summer	3.74	N-1	Summer	3.74	3.74	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
14	Cooney's Road (CNR)	4.84	Autumn	15.00	N	No constraint	10.16	Summer	8.53	N	Summer	6.37	7.01	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
15	Fairlie (FLE)	3.31	Winter	6.25	N	No constraint	2.94	Winter	2.28	N	Winter	1.51	1.59	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
16	Geraldine (GLD)	7.41	Winter	15.00	N	Security	7.59	Winter	6.99	N	Winter	6.59	6.92	N	Security	1	Distribution back-up circuit capacity	Network upgrade	No active planning	Not applicable	Upgrade/ develop back-up HV distribution feeder ties
17	Haldon Lilybank (HLB)	0.40	Winter	1.00	N	No constraint	0.60	[Select one]	0.47	N	Winter	0.30	0.33	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
18	Pareora (PAR)	9.63	Summer	10.80	N-1	No constraint	1.17	Summer	4.56	N	Summer	4.11	11.89	N	Security	2	Subtransmission circuit	Demand response	Planning stage	Not applicable	*Installed transformer capacity 2x15 MVA at N at PAR. Supply circuit capacity 2x11 MVA. Existing large consumer who plans to increase demand by 2027 is expected to engage for demand response load management and N security. Remainining loads will be within N-1
19	Pleasant Point (PLP)	5.30	Summer	6.25	N	No constraint	0.95	Summer	0.48	N	Summer	0*	0.15	N	Capacity	10+	Zone substation transformer	Network upgrade	No active planning	Not applicable	Zone substation transformer and incomer upgrade, potential future Solar PV generation plant to connect to incomer/ sub-transmission circuit peak
20	Rangitata (RGA)	9.98	Summer	10.00	N-1	No constraint	0.02	Summer	11.08	N	Summer	9.23	9.93	N	Security	1	Subtransmission circuit	Other non-traditional solution	No active planning	> 3 years	Contractual agreement with a large customer to increase capacity over manage security limits during peak loading/ Build incomers from proposed Orari GXP optionally
21	Studholme (STU)	15.10	Summer	20.00	N	Security	4.90	Summer	13.91	N-1	Summer	13.07	13.50	N-1	No constraint	1	Transpower	Network upgrade	Planning stage	< 1 year	Transpower plan to upgrade existing 2x10 MVA transformers at STU to 2x30 MVA GXP 2027
22	Tekapo Village (TEK)	4.72	Winter	13.80	N	Security	9.08	Winter	7.41	N	Winter	6.47	7.07	N	Security	1	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	Build second ZS (transformer) in Tekapo village fed by a second sub-transmission circuit beyond 2028
23	Temuka (TMK)	13.60	Summer	25.00	N-1	No constraint	11.40	Summer	10.33	N-1	Summer	9.34	10.27	N-1	Capacity	2	Other	Network upgrade	Planning stage	1 - 3 years	Outgoing 11kV distribution feeder constraints from the zone substation needs upgrades
24	Timaru 11/33 kV (TIM)	15.35	Summer	20.30	N-1	[Select one]	4.95	Summer	16.40	N	Summer	14.63	23.73	N	Security	2	[Select one]	Demand response	Planning stage	Not applicable	installed TF capacity 2x25MVA, incomer 2x20.3 MVA feeds PAR and PLP substations, demand response mentioned above for PAR directly affects this. Planned to be removed after 2028 following the commissioning of Timaru new 220/33kV GXP as PAR & PLP zone subs will be fed directly at 33kV
25	Twizel Village (TVS)	4.09	Winter	9.94	N	Security	5.85	Winter	4.65	N	Winter	3.71		N	Security	1	Subtransmission circuit	Network upgrade	No active planning	Not applicable	Build second sub-transmission circuit from Twizel GXP to Twizel village zone substation
26	Unwin Hut (UHT)	0.94	Spring	1.50	N	No constraint	0.56	Winter	0.51	N	Winter	0.45	0.50	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Meets Alpine security standard
27	Washdyke	16.98	Autumn	28.30	N-1 switched	No constraint	11.32	Autumn	5.47	N	Autumn	0.00	0.00	N	Capacity	3	Subtransmission circuit	Network upgrade	Planning stage	1 - 3 years	*New Washdyke swiching station 11kV will be commissioned in 2025 (currently under construction), to be upgraded to a zone substation 2x40MVA beyond 2027 after the commissioing of Timaru new 220/33 kV GXP with 2x120 MVA Outgoing distribution feeder upgrades to reiinforce 11kV distribution in Washdyke area have also been planned
28	Timaru Urban	31.59	Winter	39.10	N-1 switched	Security	7.51	Winter	23.46	N	Winter	19.58	23.90	N	Capacity	3	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	Short-term solution is planned to alleviate security issue for 1-2 years, planning is in progress to enhance both capacity and security constraints on sub-transmission cables from Timaru GXP to the switching stations and inter-switching station ties in Timaru CBD and Port area. The need for a new switching station and/or zone substation has also been identified and is at initial planning stage depends on future demand growth at Timaru Port
29																					

30 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

Appendix 5

Schedule 12c. Report on forecast network demand

Company Name	**Alpine Energy Limited**
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

7 ### 12c(i): Consumer Connections

sch ref							
8	*Number of ICPs connected during year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
11	*Consumer types defined by EDB**						
12	Large Scale DG		1				1
13	Large Industrial Connections	1	2	2	2	2	2
14	Commercial (medium/small)	7	6	7	9	10	10
15	Agricultural	5	10	8	5	5	5
	Residential	110	120	133	141	150	150
16	Subdivision	38	25	28	38	45	45
17	**Connections total**	161	164	178	195	212	213
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	170	180	190	200	210	210
24	Capacity of distributed generation installed in year (MVA)	1.1	27.2	1.2	1.3	1.4	1.4

25 ### 12c(ii) System Demand

sch ref								
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
28		GXP demand	152.5	160.0	182.2	188.3	199.4	204.0
29	*plus*	Distributed generation output at HV and above	7.0	13.0	13.0	14.0	14.0	15.0
30		**Maximum coincident system demand**	159	173	195	202	213	219
31	*less*	Net transfers to (from) other EDBs at HV and above						
32		**Demand on system for supply to consumers' connection points**	159	173	195	202	213	219
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	955	1,037	1,169	1,215	1,278	1,312
35	*less*	Electricity exports to GXPs	19	66	62	50	34	37
36	*plus*	Electricity supplied from distributed generation	13	25	25	27	27	29
37	*less*	Net electricity supplied to (from) other EDBs						
38		**Electricity entering system for supply to ICPs**	950	996	1,132	1,192	1,271	1,304
39	*less*	Total energy delivered to ICPs	913	957	1,089	1,146	1,222	1,254
40		**Losses**	37	38	44	46	49	50
41								
42		**Load factor**	68.0%	65.7%	66.2%	67.3%	68.0%	68.0%
43		**Loss ratio**	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%

Appendix 6

Schedule 12d. Report forecast interruptions and duration

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

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*
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	100.0	101.0	105.6	110.1	114.6	119.1
12	Class C (unplanned interruptions on the network)	91.9	78.4	75.8	73.2	70.6	68.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.49	0.54	0.59	0.65	0.70
15	Class C (unplanned interruptions on the network)	1.20	0.63	0.59	0.56	0.52	0.49

Appendix 7

Schedule 14a. Mandatory explanatory notes on forecast information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Amendment Determination 2024)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.6.

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

The nominal dollars capital expenditure forecast for 31 March 2025 represents the forecast actual capital expenditure for the year ending 31 March 2025. The constant price for 31 March 2025 represents the forecast values as per the prior year AMP.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts (using 2026 real dollars) were inflated by 2.1% for all years. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2.1% in all years.

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

The nominal dollars operational expenditure forecast for 31 March 2025 represents the forecast actual operational expenditure for the year ending 31 March 2025. The constant price for 31 March 2025 represents the forecast values as per the prior year AMP.

To derive the operational expenditure in nominal dollar terms, the constant price forecasts (using 2026 real dollars) were inflated by 2.1% for all years. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact 2.1% in all years.

Appendix 8

Schedule 17. Certification for year-beginning disclosures

We, Melissa Clark-Reynolds and Stephen Lewis, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Alpine Energy Limited prepared for the purposes of clauses 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, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Alpine Energy Limited's corporate vision and strategy and are documented in retained records.

Melissa Clark-Reynolds

27 March 2025

Stephen Lewis

27 March 2025