ASSET MANAGEMENT PLAN
UPDATE 2020 - 2030

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Alpine ENERGY

Asset Management Plan Update 2020

ALPINE ENERGY LIMITED

Planning Period: 1 April 2020 to 31 March 2030

Disclosure date: 31 March 2020

03 687 4300

alpineenergy.co.nz

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Any information contained in this document is based on information available at the time of preparation. Numerous assumptions have been made to allow future resource requirements to be assessed. These assumptions may prove to be incorrect or inaccurate, consequently, many of the future actions identified in this document may not occur.

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Directors' Statement

The purpose of our 2020 Asset Management Plan (AMP) Update is to provide insight and explanation of how we intend to provide electricity distribution services for the next ten years with information that materially adds to or changes from that in our 2019 AMP for the Planning Period 2020 - 2030. This Update should be read together with the 2019 AMP. We are committed to managing our distribution assets in a safe, reliable, and cost-effective manner that addresses required service levels and maintains a robust energy delivery system for our stakeholders.

The AMP has been published to meet our regulatory requirements for asset management under the Electricity Distribution Information Disclosure 2012.

Our distribution network is in good condition. The life of different electricity distribution assets ranges widely by asset type, from 25 to 100 years. Although some parts of our network that were installed in the 1950s and 1960s, including poles, are now nearing the end of their expected service life. The expected service life is based on the Commerce Commission's optimised deprival valuation of Fixed Assets of Electricity Lines Businesses (ODV). Overall our planned replacement rate is consistent with this criteria.

We determine when to replace assets based on specific asset condition and risk. If replacing a retired asset like-for-like would be uneconomic we replace it with an appropriate alternative product. We continue to invest in network developments including new assets to serve changing and growing consumer needs, and new technologies. We are also subject to regulatory requirements that may affect our risk and economic assessments.

Two thirds of our capital expenditure over the next ten years is targeted for replacement and renewal of existing infrastructure.

Network development capital expenditure accounts for a third of the investment in our network. This investment is specifically targeted for consumer connections, reliability safety and environment projects, and network augmentation. Developments are identified that will serve our consumers within the context of a changing environment for electricity distribution companies. Consumer preferences will drive supply solutions more and more and we will endeavour to support and give effect to this within the boundaries of the regulatory environment.

Our investment in the network is funded through our tariffs that are set in accordance with our pricing methodology. It is our intention to continue to keep tariffs within the price path set by the Commerce Commission and have a pricing methodology that is consistent with the Electricity Authority's pricing principles.

Capacity increases at grid exit points will be addressed through new investment agreements with Transpower, with a resulting price pass through to consumers as is the case now. Sole beneficiaries identified for additional capacity will have back-to-back[1] agreements to minimise the risk of stranded assets.

Please note, that no allowance has been made in the preparation of this AMP update of the effects of COVID 19, which could be significant on our ability to invest in our network and deliver our 2021 work program and possibly beyond.

The Directors

Alpine Energy Limited

[1] The sole beneficiary will contribute a substantial portion, or all of the cost of the required capacity upgrade depending on the circumstances.

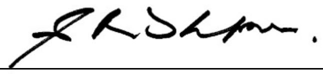
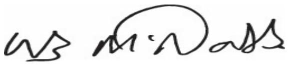
Director Certification

Certification for Asset Management Plan Update 2020.

We, Stephen Thompson and Warren McNabb, being directors of Alpine Energy Limited certify that, having made all reasonable enquiries, to the best of our knowledge—

a) the Asset Management Plan Update 2020 of Alpine Energy Limited prepared for the purposes of clause 2.6.3, 2.6.4 and 2.6.5 of the *Electricity Distribution Information Disclosure Determination 2012* (consolidated in 2018) 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.

	
Director	Director
27 March 2020	27 March 2020
Date	Date

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1. INTRODUCTION

Alpine Energy Limited is one of 29 Electricity Distribution Businesses (EDBs) in New Zealand. We supply just over 33,400 consumers in South Canterbury. Our supply area stretches from the Rangitata River in the north to the Waitaki River in the south, and from the coast inland to Mt Cook.

In March 2019 we published a comprehensive Asset Management Plan (AMP), which is available on our website www.alpineenergy.co.nz.

In accordance with the *Electricity Distribution Information Disclosure Determination 2012* (the Determination), the Commerce Commission allows EDBs to complete and publicly disclose an AMP Update rather than a full comprehensive AMP subject to certain conditions. Subject to these conditions, the 2020 disclosure year qualifies as one of these occasions and Alpine Energy Limited has chosen to issue an AMP Update for the 31 March 2020 disclosure date.

This document is Alpine Energy's 2020-2030 electricity network AMP Update and assumes the reader is familiar with our 2019-2029 comprehensive AMP. The Update provides information that materially adds to, or changes, that in the comprehensive AMP in accordance with clause 2.6.5 of the Determination.

1.1 INFORMATION DISCLOSURE REQUIREMENTS

Clause 2.6.3 of the *Electricity Distribution Information Disclosure Determination 2012* requires us to publicly disclose, before 1 April 2020, an AMP Update, in accordance with clauses 2.6.4, 2.6.5, and 2.6.6.

For the purpose of clause 2.6.5 of the Determination, 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 or in the last AMP update disclosed under this section;
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

In addition, clause 2.6.6 requires EDBs to complete the following reports as set out in the schedules:

1) Report on Forecast Capital Expenditure in Schedule 11a;
2) Report on Forecast Operational Expenditure in Schedule 11b;
3) Report on Asset Condition in Schedule 12a;
4) Report on Forecast Capacity in Schedule 12b;
5) Report on Forecast Network Demand in Schedule 12c;
6) Report on Forecast Interruptions and Duration in Schedule 12d;

1.2 STRUCTURE

This AMP Update is structured to meet the disclosure requirements as described above, and is in the same format as our previous comprehensive AMP. Where more detail is required on a specific topic we encourage the reader to revert to our 2019-2029 comprehensive AMP that is available on our website as stated above.

Sections 2 to 5 provide the information as required under clause 2.6.5(2) to (4) of the Determination and section 6 lists all the disclosure schedules 11a through 12d.

Information disclosure data given in this document are based on the regulatory period from 1 April to the following year 31 March. All time based graph data that is not information disclosure data to the Commerce Commission, is presented on a calendar year basis.

2. MATERIAL CHANGES TO THE NETWORK DEVELOPMENT PLAN

This section details all material changes, or additions, in network development plans for the respective areas as described in our 2019 AMP. Where changes or more accurate data is available, graphs and tables have been updated.

Distributed generation (DG)

Distributed generation and the effects of its penetration on distributions networks are a very topical subject. Terminology like "open networks"[2] are being adopted in the industry for describing the requirement that these technologies be easily connected to distribution networks. Our network development plan now includes details of current levels of installed DG as well as projected or forecast levels. The details are provided in the sections below for the seven GXP areas our network covers.

At the time of writing, the total DG capacity installed on our network was approximately 2 MW of which the majority is PV with two small biogas installations. This installed DG is on a cumulative installed transformer capacity of 59 MVA. On average a typical distribution network can accommodate between 27% and 45% of DG penetration on the installed transformer capacity, before network constraints are experienced.[3] The forecast modelling used in sections 2.1 through 2.7 is based on a best fit function of all historical actual data. This model is updated regularly and will be adjusted if external triggers such as government policy or subsidies are introduced.

For the purposes of this AMP Update, details with respect to the embedded Opuha generation as described in section 5.10.1 of our 2019 AMP has not changed. This AMP Update focusses on DG that could present us with network development challenges.

Electric vehicles (EV)

Electric vehicles and the deployment of charging stations is another topical issue under discussion in the industry. When a consumer purchases an EV and installs a charging station at his home, there is no mechanism in place to alert us to this fact unless the consumer applies to have the service fuse upgraded to a higher rating. The implication is that if a sufficient number of consumers supplied by the same transformer and low voltage (LV) network installs charging stations, our network infrastructure could be under rated to supply this load. In addition, this could lead to a doubling of our system peak load if all the consumers decide to charge their EVs when they arrive home from work. This scenario is detailed in section 5.4 of our 2019 AMP.

Since this EV charging infrastructure could impact on existing low voltage (LV) infrastructure, and to an extent on high voltage (HV) infrastructure, we are monitoring the deployment of charging stations across our network. As reported by the International Energy Agency[4], government policy is still the main driver for the uptake of EVs with the associated challenges that charging stations present. Any government policy in this regard would be a trigger for us to adjust our modelling of EV charger load. It is however important to note that the actual deployment and location of fast charging stations is largely unknown until we receive an application for power supply.

Figure 1 shows all the current EV charging sites and charging stations on a per GXP basis while Figure 2 details the cumulative charging capacity on the same basis.

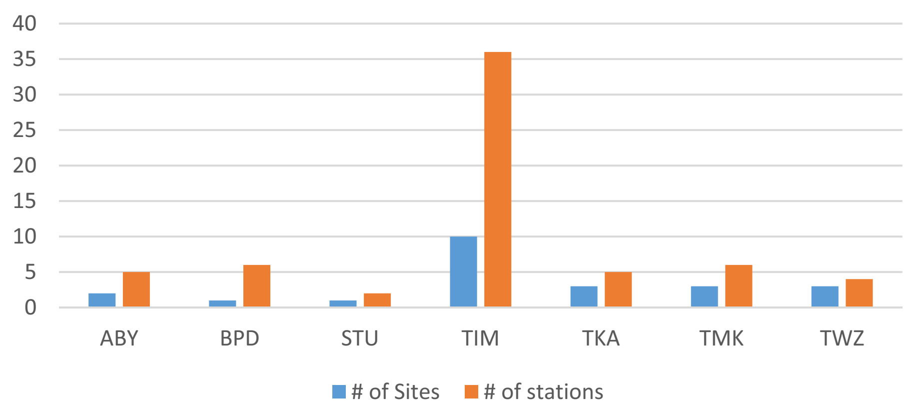

Figure 1: Number of EV charging sites and stations per GXP

[2] Open networks are networks that allows and encourages the uptake of new technologies to be connected.
[3] International Energy Agency Task V Report IEA-PVPS T5-10:2002, *Impacts of power penetration from photovoltaic power systems in distribution networks*. This is provided the minimum load on the system during PV generation is also 27% to 45% of the maximum load.
[4] *Global EV Outlook 2018* page 10

We are not monitoring private residential EV charger uptake at this point of time mainly because we have no mechanism in place whereby consumers are required to inform us when they do install a charger. We are undertaking a Network Transformation Readiness initiative that will address this (and other DG related topics) and set actions to monitor, regulate and manage EV charger uptake. Based on demographics we would be expected that residential EV uptake will be higher in the Timaru region than all the other regions. This is supported by the data in Figure 1 and Figure 2 respectively.

It is important to note that for Timaru, one single site in Washdyke comprising six charging stations for Tesla vehicles, has a capacity of 720 kW or just over 70% of the total charger capacity in Timaru. This type of installation, to an extent does skew the data.

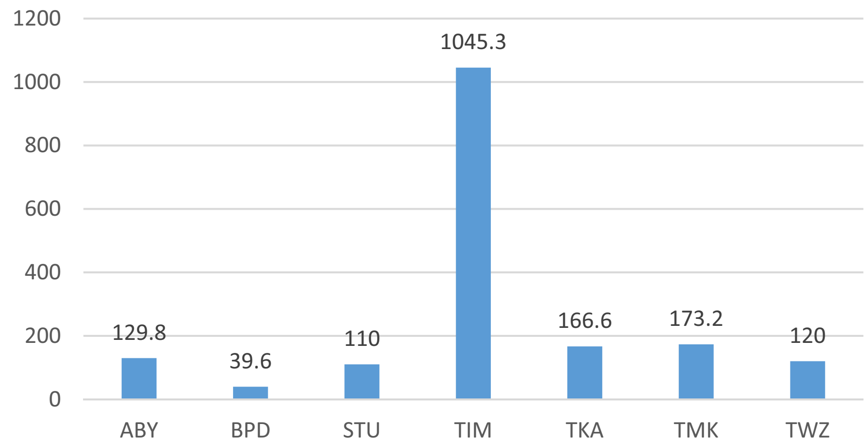

Figure 2: Total EV capacity per GXP in kW

The data presented in the figures above is broken down in more granular format to present the number and capacity of EV chargers down to substation feeder level. This enables us to monitor and to potentially manage feeder loading as well as study the impact of charging habits on our network.

There are currently 3000 registered EVs in Canterbury of which 150 is registered in Timaru.[5] 113 of these are Nissan Leaf models, there are 8 Hyundai Ionic and Kona models, 19 Mitsubishi Outlander models and 6 Toyota Prius models. 131 are private passenger vehicles and 19 are company owned. Figure below shows the registration dates for the vehicles registered in South Canterbury.

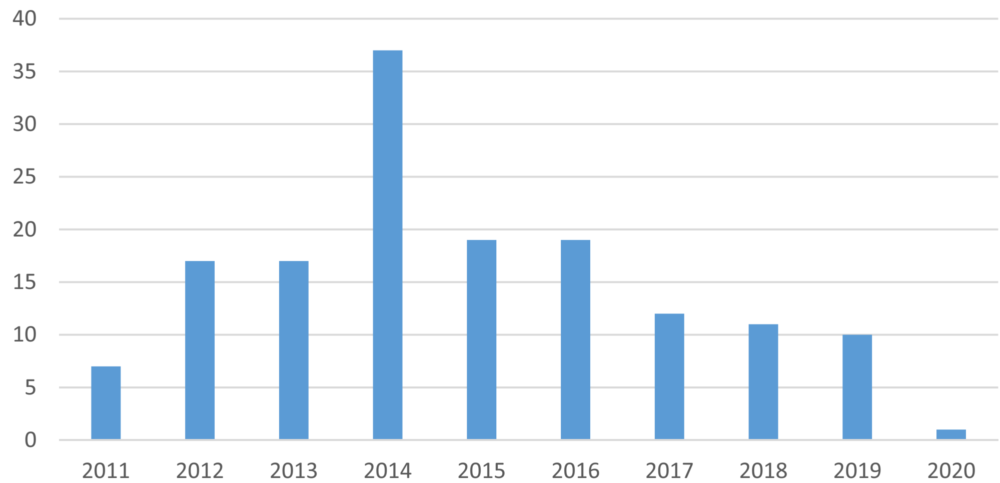

Figure 3: EV registrations in South Canterbury by year

[5] Ministry of Transport website under Vehicle Fleet Statistics as at 17/03/2020. Note the data presented is based on "Location" information.

2.1 ALBURY REGION

2.1.1 DEMAND FORECAST

Demand in this area is growing slowly. Figure 4 is shown to correct a data error in the same graph in the previous AMP.

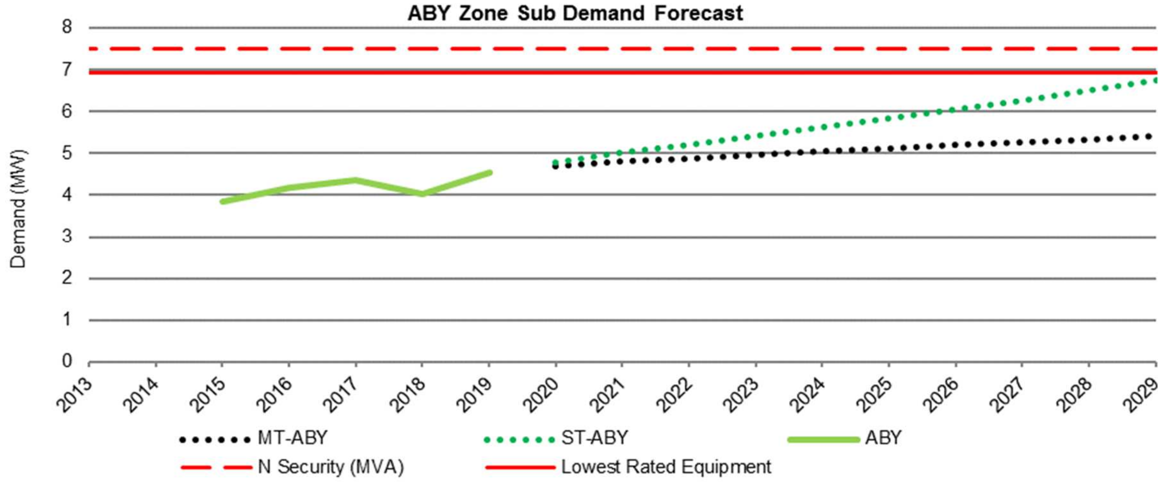

Figure 4: Albury substation demand forecast, supply security, and equipment rating

2.1.2 DISTRIBUTED GENERATION

Distributed generation (DG) growth in the Albury and Fairlie areas is slow but steady at an average of 14 kW capacity per year, predominantly in the Fairlie area. There are no evident effects (negative or positive) currently observed due to DG uptake in the area. Export to the network is minimal due to majority of consumers being focused on peak lopping[6] rather than export. The predominant type of DG in the area is PV.

The DG in this area is currently at 5.4% of the installed distribution transformer capacity.

Figure 5 shows the annual uptake of DG connected to the Albury GXP, while Figure 6 shows the cumulative uptake of DG and the forecast uptake.

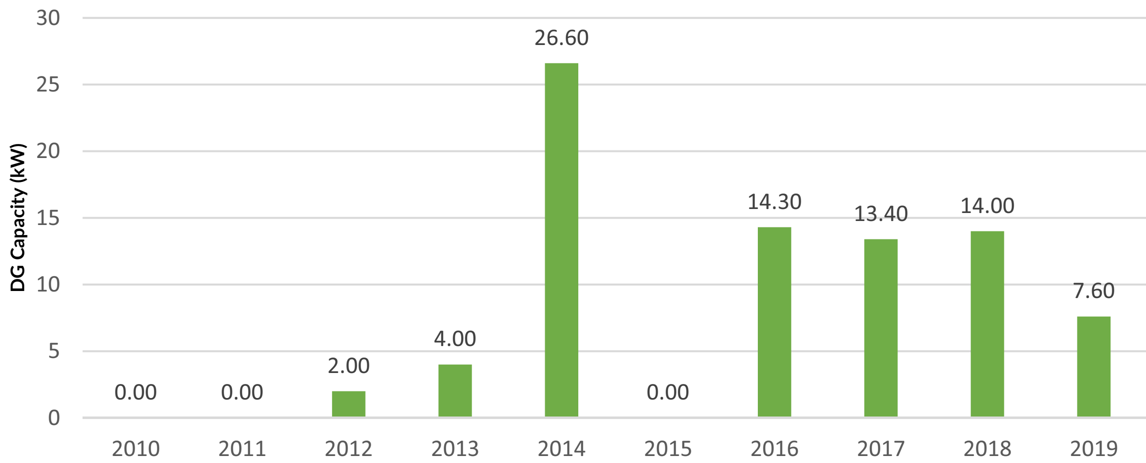

Figure 5: Albury GXP annual DG uptake

[6] Peak lopping is when consumers use the energy generated by their PV installation to offset their own consumption, rather than injecting the energy into the electricity network for someone else to use.

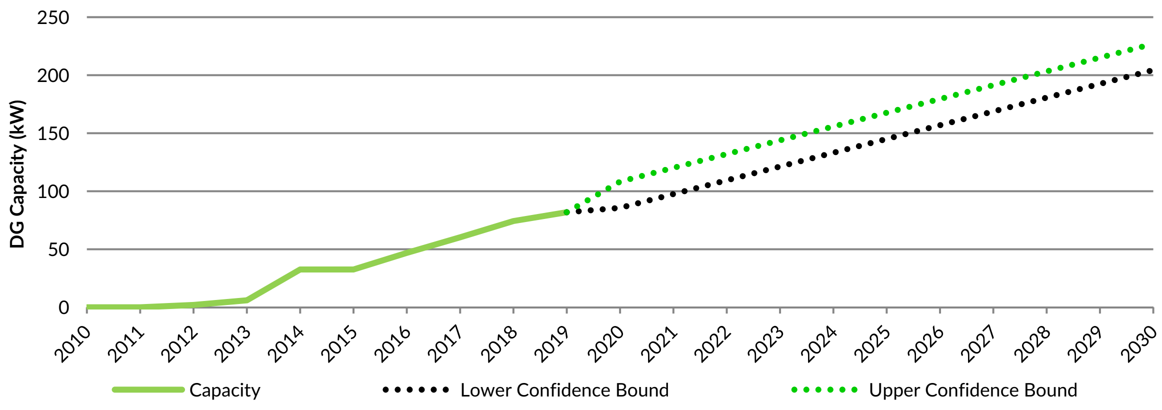

Figure 6: Albury GXP cumulative DG uptake and growth forecast

2.1.3 ELECTRIC VEHICLES

Uptake of EV chargers in the region is slow with only two publicly accessible sites commissioned in and around the Fairlie Township. One 50 kW public charging site owned by Alpine is located across the road from the district council offices with two fast charging connectors. Another site is privately owned by a local camping ground providing three stations with charging capacity of up to 6.6 kW each.

2.2 BELLS POND REGION

2.2.1 DEMAND FORECAST

Demand off this GXP is growing steadily. There are no additional substantial load increases and only a single upgrade of a voltage regulator on the Waihuna feeder. This project valued at $150 k is currently planned for 2020/21.

We are also planning to replace six 110 kV current transformers at this GXP due to failures of a similar type on Transpower's network. The value of these replacements is estimated at $200 k.

2.2.2 DISTRIBUTED GENERATION

DG growth in Bells Pond region is very slow with the largest uptake occurring in 2014 and 2015. In 2018 and 2019 there were no further installations. Figure 5 list the annual uptake of DG connected to the Bells Pond GXP, while Figure 6 shows the cumulative uptake of DG and the forecast uptake.

Figure 7 shows the annual uptake of DG connected to the Bells Pond GXP, while Figure 8 shows the cumulative uptake of DG and the forecast uptake.

The DG in this area is currently at 4.5% of the installed distribution transformer capacity.

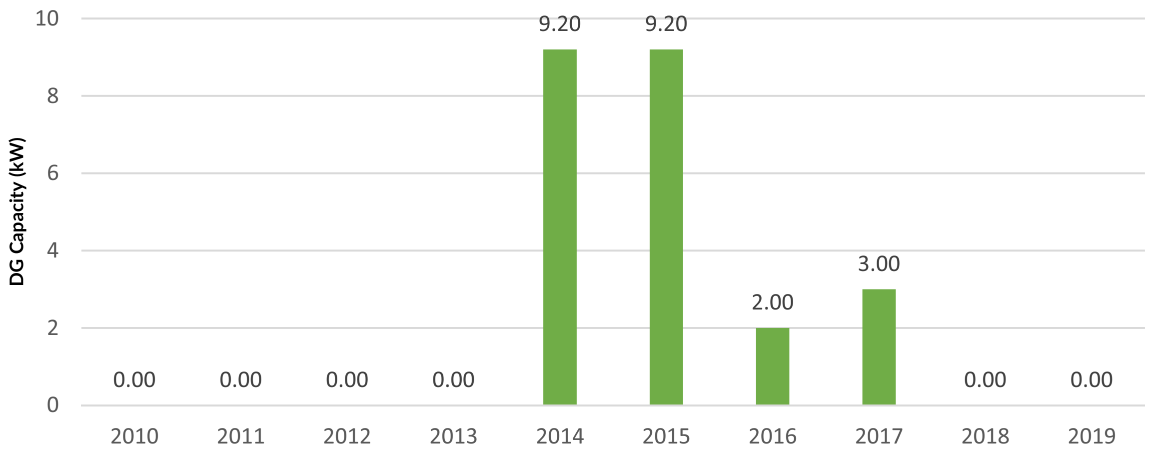

Figure 7: Bells Pond GXP annual DG uptake

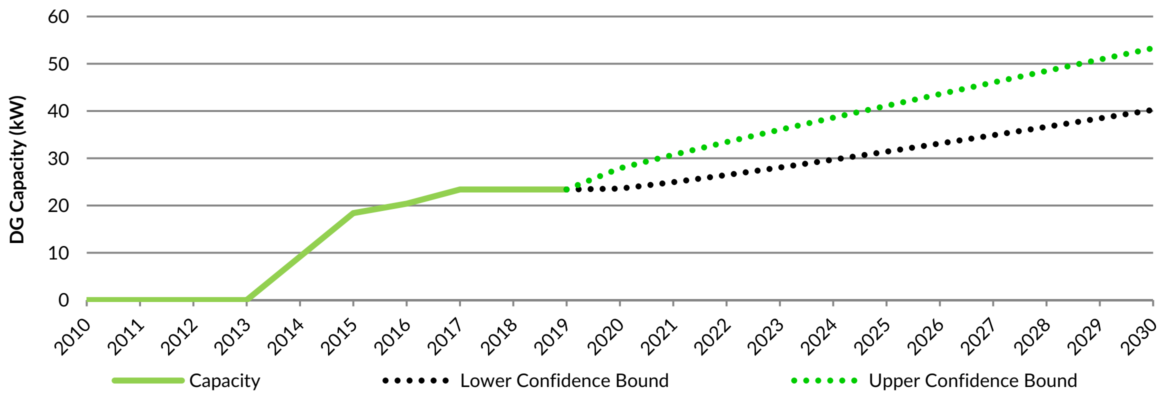

Figure 8: Bells Pond GXP cumulative DG uptake and growth forecast

2.2.3 ELECTRIC VEHICLES

Currently there is one privately owned EV charger site located at the camp grounds in Glenavy Township providing six stations at 6.6 kW each. Since this GXP supplies mainly rural farming communities, we do not expect a significant uptake in EVs at this point in time.

2.3 STUDHOLME REGION

2.3.1 DEMAND FORECAST

Demand off this GXP is growing steadily. There are no additional substantial load increases. Actual demand in 2019 was down from 2018. There are no additional projects planned at this GXP. Prospective projects depend largely on customer initiation mainly from Fonterra.

2.3.2 DISTRIBUTED GENERATION

Distributed generation (DG) growth in the Studholme area is slow but steady at an average of 8.5 kW capacity per year. The area witnessed an increase in 2014 and nothing in 2016. The last three years have seen an increase in uptake and has been around the 14 kW mark per annum. There are no evident effects (negative or positive) currently observed due to DG uptake in the area. The predominant type of DG in the area is PV.

Figure 9 shows the annual uptake of DG connected to the Studholme GXP, while Figure 10 shows the cumulative uptake of DG and the forecast uptake.

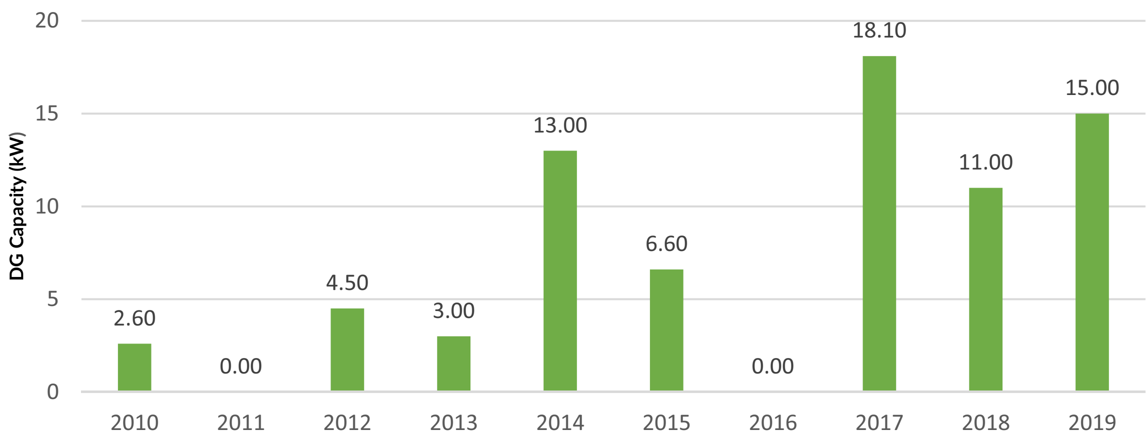

Figure 9: Studholme GXP annual DG uptake

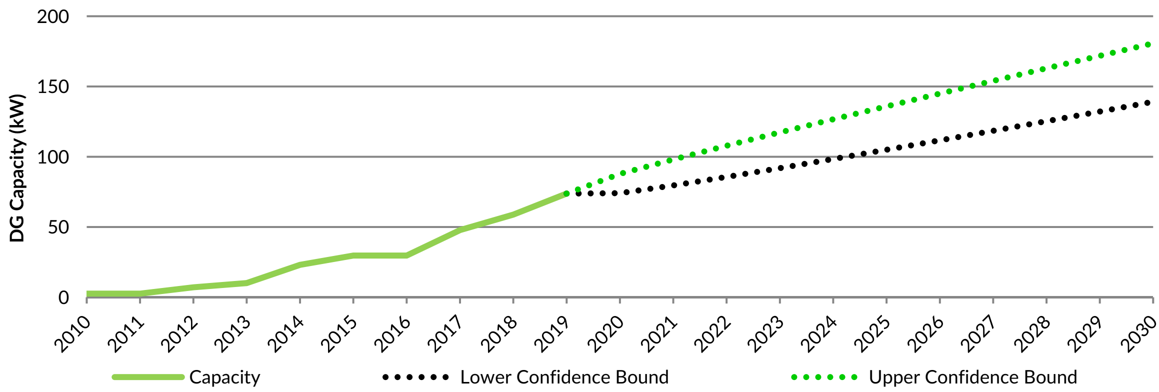

Figure 10: Studholme GXP cumulative DG uptake and growth forecast

The DG in this area is currently at 4.5% of the installed distribution transformer capacity.

2.3.3 ELECTRIC VEHICLES

Uptake of EV chargers in the region is very slow with only one publicly accessible site commissioned in and around the Waimate Township. The only site is a 50 kW public charging owned by Alpine and located in the heart of the Waimate Township with two connector types.

2.4 TEKAPO REGION

2.4.1 DEMAND FORECAST

Load growth in the Tekapo township is healthy with a number of subdivisions and commercial developments underway. There are no additional projects planned beyond those detailed in the previous AMP. Upgrading of the Tekapo zone substation transformer has been scheduled but the definitive timing is dependent on load growth. This site is configured to connect our mobile substation with 50% more capacity than the current transformer.

We have replaced our Balmoral substation feeding the Simon's Pass area in 2019 due to the age of the equipment and the fact that we did not have any spares for the transformer due to its unique characteristics. The replacement substation has been renamed to Old Man Range (OMR) substation due to its location. Capacity has been increased and the demand forecast is depicted in Figure 11 and is sufficient to beyond the planning period.

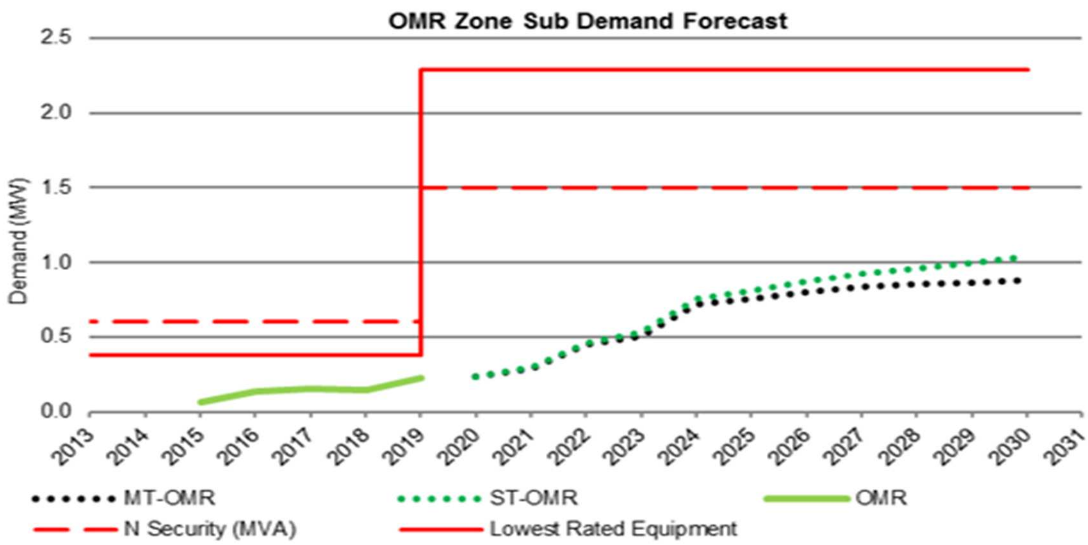

Figure 11: OMR substation demand forecast, supply security, and equipment rating

2.4.2 DISTRIBUTED GENERATION

Distributed generation (DG) uptake in the Tekapo GXP regions is slow with an average of 15 kW capacity installed per annum. The predominant type of DG in the area is PV and small scale batteries for controls or storage. There is a

100 kW Biogas generator commissioned in 2018 by a dairy farm in the Simons Pass area. This generator is currently set not to inject any power into our network.

Most DG applications are residential concentrated around the township areas. One school in the Tekapo area has a 3 kW PV system as part of the government initiative to encourage green energy for schools. Commercial entities in the region have also showed substantial interest in DG with growth in local businesses, motels and hotels investing in PV systems.

Figure 12 shows the annual uptake of DG connected to the Tekapo GXP, while Figure 13 shows the cumulative uptake of DG and the forecast uptake.

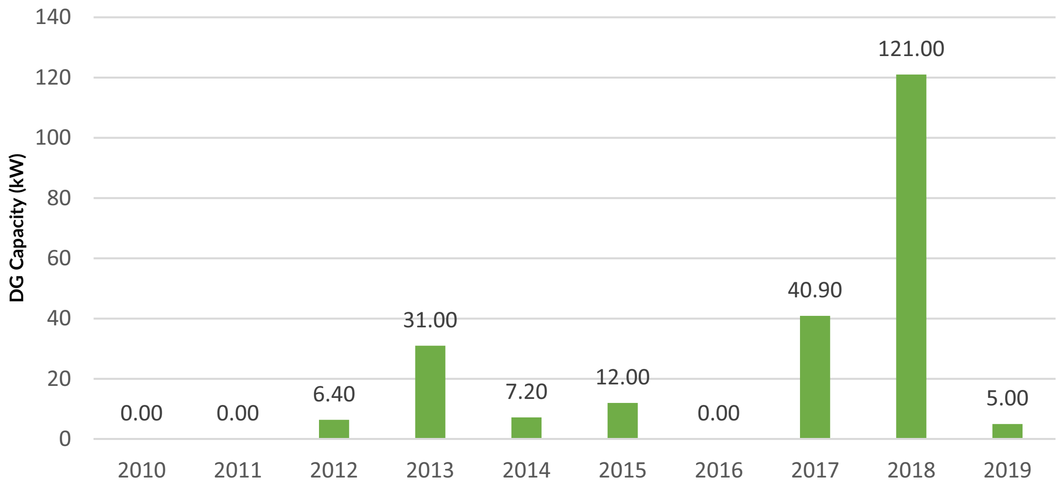

Figure 12: Tekapo GXP annual DG uptake

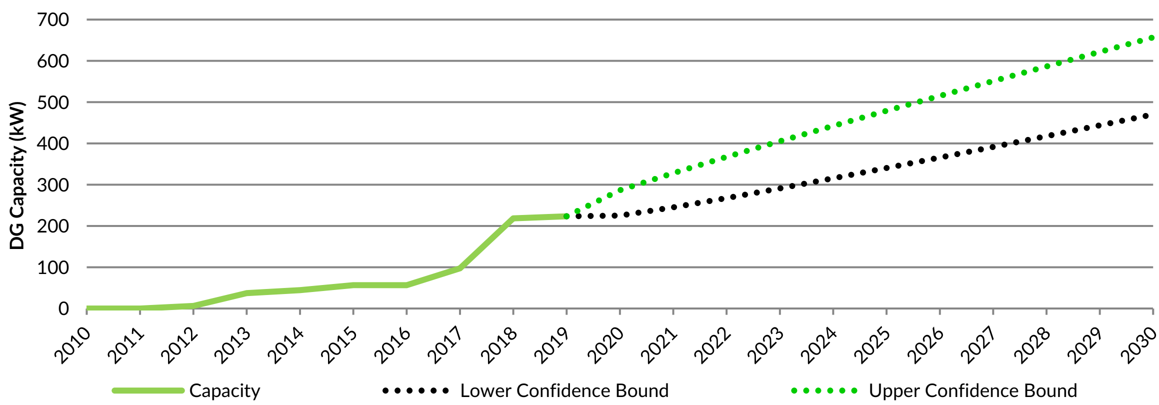

Figure 13: Tekapo GXP cumulative DG uptake and growth forecast

While the uptake in 2018 was promising the 2019 numbers were substantially down. We believe the negative publicity on television in the Fair Go program has had an influence on the uptake of PV in Tekapo and other regions. Tekapo is however an area where we will benefit from the uptake of PV, especially if it is accompanied by battery storage. Then it would help to manage demand at zone substation and GXP level with possible deferral of capital investment.

The DG in this area is currently at 6.3% of the installed distribution transformer capacity.

2.4.3 ELECTRIC VEHICLES

Uptake of EV chargers in the Tekapo region is slow with only two publicly accessible site commissioned in the Tekapo Township. One site is owned by Alpine (2 x 50 kW stations) and another by the Four Square supermarket (2 x 25 kW stations). There is another privately owned site on the Tekapo Backpackers hostel (5 kW).

2.5 TEMUKA REGION

2.5.1 DEMAND FORECAST

Demand forecast in this region has not changed significantly from last years' forecast. The GXP continues to operate just above the N-1[7] security level during peak loading periods. We will be replacing the Geraldine zone substation transformer in 2020 calendar year due to the condition of the paper insulation of the current transformer. This replacement will also increase the available transformer capacity to this area.

The Temuka GXP upgrade is currently under review between Transpower and ourselves. The forecast expenditure around this development will as a result be deferred from the previous anticipated timeframe, possibly to 2022. The two Clandeboye (Fonterra) zone substations continue to operate at their N-1 capacity. Any upgrade of these substations will be at the request of Fonterra either for additional capacity, or increased security of supply.

2.5.2 DISTRIBUTED GENERATION

Distributed generation (DG) uptake in the Temuka GXP regions has picked up since 2015 with an average of 90 kW annually. The predominant type of DG in the area is PV and small scale batteries for controls or storage. A large percentage of the DG growth is residential mostly concentrated around the township areas.

As part of the government initiative to fund and support solar installations for schools, seven schools around the Temuka region have 73 kW installed PV generation shared between them. The largest is the Geraldine High school with 45 kW solar system.

Commercial entities in the region have also shown interest in DG with growth in local businesses investing in PV systems. This is expected to grow with more corporate groups (e.g. Foodstuffs, Fonterra, etc.) setting cost and emissions reduction targets.

Figure 14 shows the annual uptake of DG connected to the Temuka GXP, while Figure 15 shows the cumulative uptake of DG and the forecast uptake.

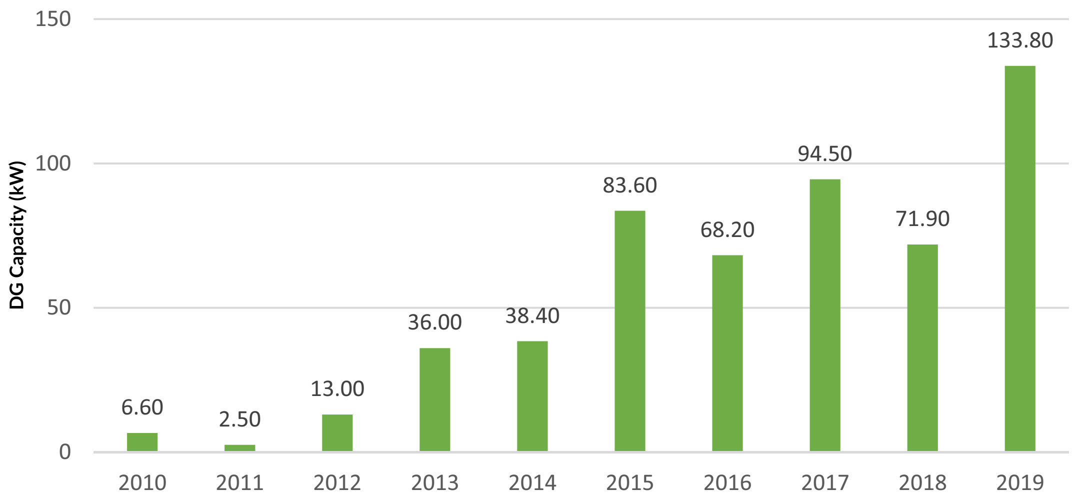

Figure 14: Temuka GXP annual DG uptake

[7] N-1 means that supply is not affected for a single contingent event, or, the loss of a single line or transformer will not compromise supply.

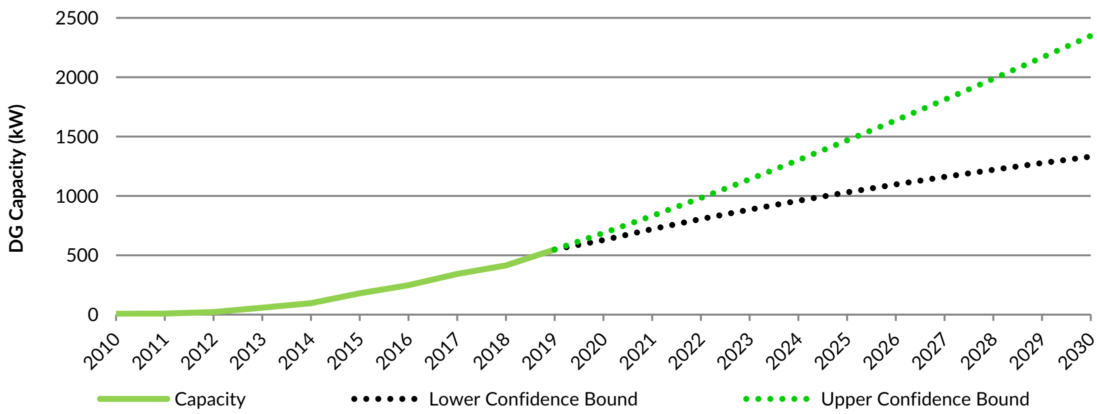

Figure 15: Temuka GXP cumulative DG uptake and growth forecast

The uptake of DG in Temuka is typical for larger urban areas where the population density is higher. The trend is similar to the uptake in Studholme (i.e. Waimate township) and Timaru. These centres also have a higher installed capacity base and can therefore accommodate more DG penetration.

The DG in this area is at 4.9% of the installed distribution transformer capacity.

2.5.3 ELECTRIC VEHICLES

Uptake of EV chargers in the Temuka region is slow with only two publicly accessible site commissioned in the Temuka (25 kW) and Geraldine (50 kW) Townships. There is another District Council owned site on the Winchester showgrounds (10 kW).

2.6 TIMARU REGION

2.6.1 DEMAND FORECAST

Load growth in this area has been steady and mainly due to light industrial development in the Washdyke area. Demand on the three main switching stations supplying the urban township area has been flat.

The upgrade of the Timaru zone substation 33 kV switchgear and protection has been deferred by two years to 2022/24.

2.6.2 DISTRIBUTED GENERATION

Distributed generation growth in the Timaru area is strong and steady at an average of 146.9 kW capacity per annum over the last six years. The area witnessed a high increase in 2014 and has been steady since. There are no evident effects (negative or positive) currently observed due to DG uptake in the area. Export to the network is minimal due to majority of consumers being focused on peak lopping rather than export. The predominant type of DG in the area is PV.

The DG in this area is currently at 2.5% of the installed distribution transformer capacity.

Figure 16 shows the annual uptake of DG connected to the Timaru GXP, while Figure 17 shows the cumulative uptake of DG and the forecast uptake.

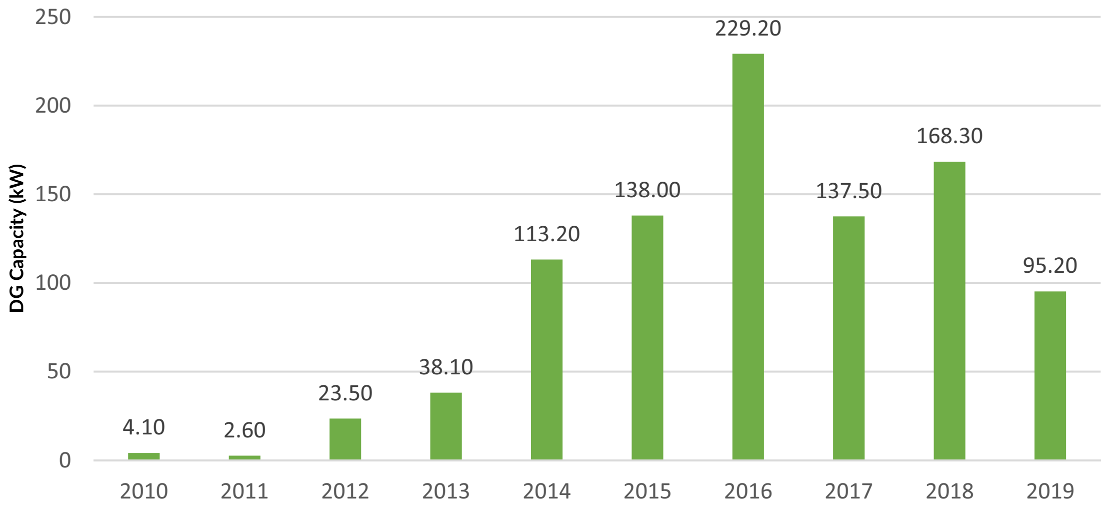

Figure 16: Timaru GXP annual DG uptake

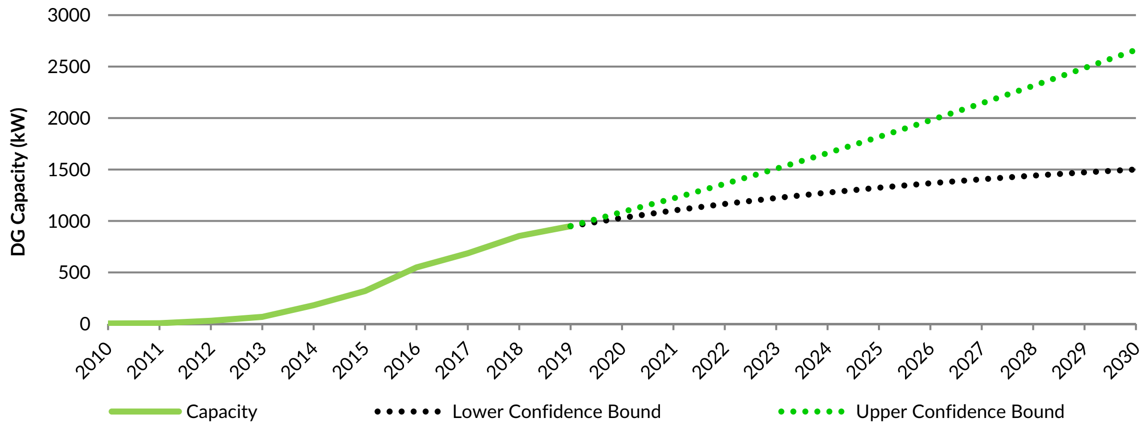

Figure 17: Timaru GXP cumulative DG uptake and growth forecast

2.6.3 ELECTRIC VEHICLES

Uptake of EV chargers in the region is slow with only ten publicly accessible sites, 9 commissioned in and around the Timaru district. They range from 3 kW to 120 kW per charger.

2.7 TWIZEL REGION

2.7.1 DEMAND FORECAST

There are two large staged subdivisions and several small (five lot) subdivisions underway in Twizel. Despite this, demand is growing slowly and there are presently no significant step increases. This may be due to many residences being used for vacation or weekend getaway. Load growth based on the last five years indicate a capacity constraint towards the end of the planning period.

2.7.2 DISTRIBUTED GENERATION

Distributed generation (DG) growth in the Twizel is slow but steady at an average of 14.7 kW capacity per year since 2015. The area witnessed a large increase in 2015 and 2017 with 18.4 kW uptake. Since 2017 it has been gradually reducing with 2019 seeing only 10.3 kW uptake. There are no evident effects (negative or positive) currently observed due to DG uptake in the area. The predominant type of DG in the area is PV.

With the increased tourism attraction to the Tekapo-Twizel areas, and their well-known clear skies, there is potential of PV uptake to increase with the increase in developments.

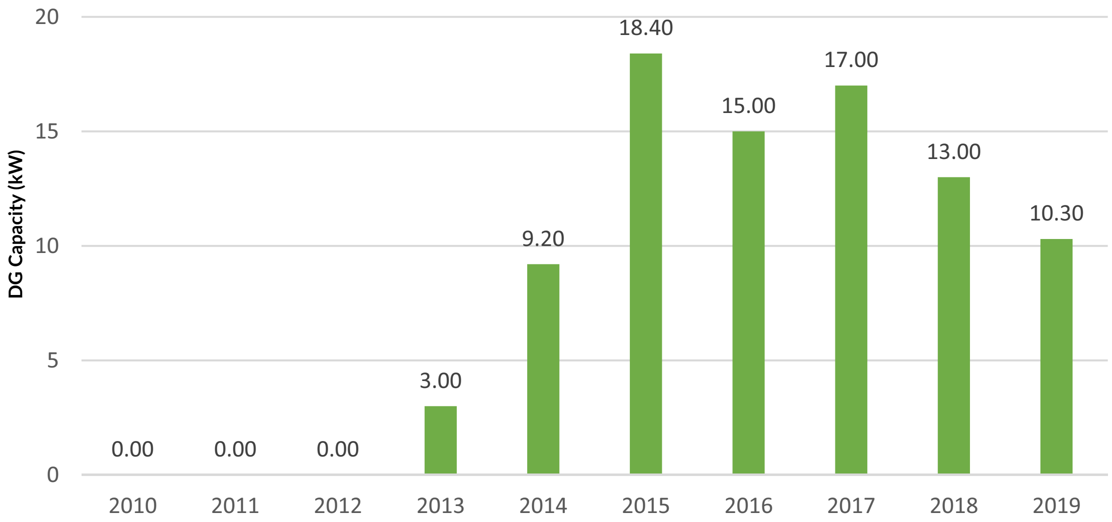

Figure 18: Twizel GXP annual DG uptake

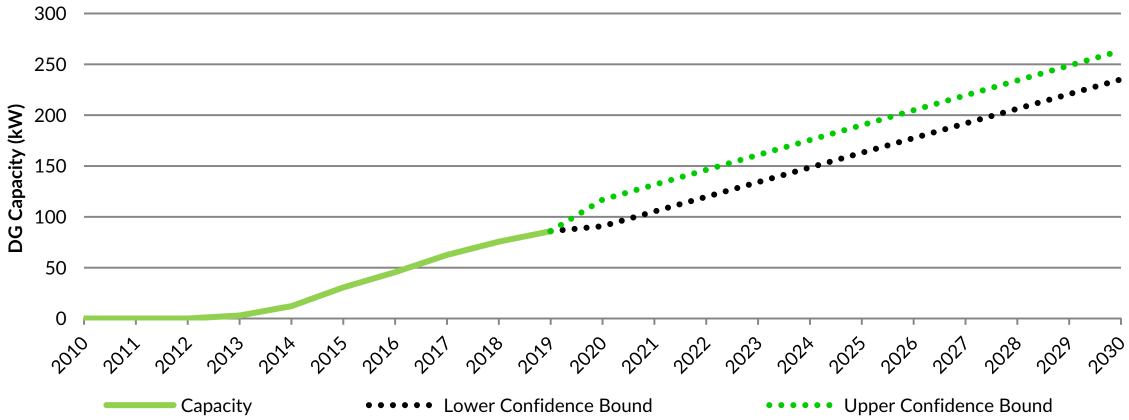

Figure 19: Twizel GXP cumulative DG uptake and growth forecast

The DG in this area is currently at 2.6% of the installed distribution transformer capacity.

Figure 18 shows the annual uptake of DG connected to the Twizel GXP, while Figure 19 shows the cumulative uptake of DG and the forecast uptake.

2.7.3 ELECTRIC VEHICLES

Uptake of EV chargers in the region is slow with only one publicly accessible site (2 x 50 kW stations owned by AEL) commissioned in the Twizel Township. There are another two privately owned sites one at the Meridian Energy offices and one close to Lake Pukaki (2 x 5 kW stations for venue patrons).

3. MATERIAL CHANGES TO LIFECYCLE ASSET MANAGEMENT

There have been no material changes to the methodologies used in the lifecycle management of our assets during the last year. We continue to progress in utilising our asset management system more effectively as well as improving our asset data. We have started a program to move from mainly age based asset condition to an actual condition based system.

We are using smart meter data increasingly to assess actual diversified loading on our network with a view to optimise our capital investments by not spending too early. There are also numerous benefits to our consumers through improved quality of supply and safety aspects.

We have started and will continue with a program to have our overhead conductor tested by independent specialists. This will aid in more accurately assessing the end of life for various types of conductor used in different regions on our network.

4. REASONS FOR MATERIAL CHANGES TO FORECAST EXPENDITURE

It is our intention to stay within the allowances set by the Commerce Commission for both capital and operational expenditure in the default price path period 3 (DPP3). As before, our expenditure on the network is based on risk and we will prioritise expenditure on this basis.

We like all other EDBs and organisations, comply with traffic management requirements set by Transport NZ and local authorities. Increased requirements have a cost impact and can also affect network reliability if it takes longer to perform network switching during unplanned outages.

Expenditure on vegetation management is also impacted by traffic management requirements. Weather events are increasingly severe. The frequency of extreme events (eg those previously considered to have a frequency of only one in fifty or one in a hundred years) is increasing. We are looking forward to the governments revision of the *Electricity Hazards from Trees Regulation 2003*. These regulations have not enabled EDBs to effectively manage vegetation in close proximity to our infrastructure.

4.1 CAPITAL EXPENDITURE

The is no material change to the forecast network capital expenditure over the DPP3 period. However, we are forecasting a 13% increase in network capital expenditure for the first four years of DPP4 compared to the forecast last year. The main reasons for this are:

- Expenditure on overhead line infrastructure coming to end of life
- Upgrading of overhead and underground low voltage lines and cables to ensure load requirements from EV chargers can be met, and to ensure "open network" architecture for the connection of distributed generation
- Upgrading of main feeders to ensure network security levels are maintained

There is a material change to non-network capital expenditure. This budget forecast is 85% higher than last year's forecast. The main reason for this is a number of IT and logistics projects that was not started in the 2019/20 financial year which has been rolled over to 2020/21.

Our overall capital expenditure forecast is 4% higher than the 2019/20 forecast for the nine overlapping years. However, our overall capital expenditure for DPP3 is in line with our allowances.

4.2 OPERATIONAL EXPENDITURE

There is no material change to our operational expenditure forecast. We are forecasting an operational expenditure in line with our allowances under DPP3.

5. ASSET MANAGEMENT PRACTICES

There have been no material changes to our asset management practices during the last twelve months that would affect the disclosure of Schedule 13 contents.

As mentioned in section 3 above, we are utilising our asset management system more as we continue to develop and increase the functional use of the system. Improved data quality aids in making more informed decision with respect to maintenance regimes as well as asset replacement decisions. We have developed and will be trialling an electronic project documentation issuing and as-built system to expedite and improve quality control on project documentation handling.

6. DISCLOSURE SCHEDULES 11A, 11B, 12A, 12B, 12C, 12D

6.1 FORECAST CAPITAL EXPENDITURE – SCHEDULE 11A

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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).

This information is not part of audited disclosure information.

sch ref												
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	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
11	System growth	1,072	1,557	2,601	800	800	600	1,300	1,300	1,300	1,300	2,800
12	Asset replacement and renewal	8,045	10,992	10,699	13,100	12,715	9,355	10,595	10,095	11,475	10,245	11,070
13	Asset relocations	350	620	500	500	500	500	1,000	1,000	1,000	1,000	-
14	Reliability, safety and environment:											
15	Quality of supply	626	580	436	532	528	528	716	741	729	680	680
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	765	835	630	512	485	210	470	175	150	500	120
18	**Total reliability, safety and environment**	1,391	1,415	1,066	1,044	1,013	738	1,186	916	879	1,180	800
19	**Expenditure on network assets**	12,858	16,584	16,866	17,444	17,028	13,193	16,081	15,311	16,654	15,725	16,670
20	Expenditure on non-network assets	2,842	1,539	689	626	738	793	670	676	614	760	696
21	**Expenditure on assets**	15,700	18,123	17,555	18,070	17,766	13,986	16,751	15,987	17,268	16,485	17,366
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	13,700	16,123	15,555	16,070	15,766	11,986	14,751	13,987	15,268	14,485	15,366
28												
29	Assets commissioned	10,494	17,329	12,349	16,466	12,560	13,192	11,545	15,193	12,062	15,691	12,160
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	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
32		**$000 (in constant prices)**										
33	Consumer connection	2,000	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961
34	System growth	1,072	1,674	3,187	980	882	686	1,275	1,275	1,275	1,275	2,745
35	Asset replacement and renewal	8,045	11,247	11,960	12,490	12,172	9,172	10,387	9,897	11,250	10,044	10,853
36	Asset relocations	350	608	490	490	490	490	980	980	980	980	-
37	Reliability, safety and environment:											
38	Quality of supply	626	784	643	737	733	733	702	726	715	667	667
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	765	819	618	502	475	206	461	172	147	490	118
41	**Total reliability, safety and environment**	1,391	1,603	1,261	1,239	1,209	939	1,163	898	862	1,157	784
42	**Expenditure on network assets**	12,858	17,092	18,859	17,161	16,714	13,248	15,766	15,011	16,327	15,417	16,343
43	Expenditure on non-network assets	2,842	2,059	1,117	563	671	725	657	663	602	745	683
44	**Expenditure on assets**	15,700	19,151	19,975	17,724	17,385	13,973	16,422	15,674	16,929	16,162	17,026
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
Difference between nominal and constant price forecasts		**$000**										
Consumer connection		-	39	39	39	39	39	39	39	39	39	39
System growth		-	(117)	(586)	(180)	(82)	(86)	25	25	25	25	55
Asset replacement and renewal		-	(255)	(1,261)	610	543	183	208	198	225	201	217
Asset relocations		-	12	10	10	10	10	20	20	20	20	-
Reliability, safety and environment:												
Quality of supply		-	(204)	(207)	(205)	(205)	(205)	14	15	14	13	13
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		-	16	12	10	10	4	9	3	3	10	2
Total reliability, safety and environment		-	(188)	(195)	(195)	(196)	(201)	23	18	17	23	16
Expenditure on network assets		-	(508)	(1,993)	283	314	(55)	315	300	327	308	327
Expenditure on non-network assets		-	(520)	(428)	63	66	68	13	13	12	15	14
Expenditure on assets		-	(1,028)	(2,420)	346	380	13	328	313	339	323	341

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
*Consumer types defined by EDB**		**$000 (in constant prices)**					
Low User Charge		100	98	98	98	98	98
015		280	275	275	275	275	275
360		240	235	235	235	235	235
Assessed		460	451	451	451	451	451
TOU400		920	902	902	902	902	902
**include additional rows if needed*							
Consumer connection expenditure		2,000	1,961	1,961	1,961	1,961	1,961
less Capital contributions funding consumer connection		1,500	1,500	1,500	1,500	1,500	1,500
Consumer connection less capital contributions		500	461	461	461	461	461

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-					
Zone substations	2	2	1,962	196	196	-
Distribution and LV lines	265	564	-	-	-	-
Distribution and LV cables	300	294	294	294	294	294
Distribution substations and transformers	120	147	147	147	147	147
Distribution switchgear	235	147	147	147	147	147
Other network assets	150	373	-	-	-	-
System growth expenditure	1,072	1,526	2,550	784	784	588
less Capital contributions funding system growth	300	300	300	300	300	300
System growth less capital contributions	772	1,226	2,250	484	484	288

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
Subtransmission	100	294	225	29	-	-
Zone substations	555	1,569	1,304	3,382	3,137	696
Distribution and LV lines	3,870	5,712	5,433	5,387	5,990	5,539
Distribution and LV cables	700	981	637	1,382	686	735
Distribution substations and transformers	1,770	1,618	1,667	1,667	1,667	1,667
Distribution switchgear	130	98	49	-	-	-
Other network assets	920	505	1,174	995	985	534
Asset replacement and renewal expenditure	8,045	10,776	10,489	12,843	12,466	9,172
less Capital contributions funding asset replacement and renewal	200	200	200	200	200	200
Asset replacement and renewal less capital contributions	7,845	10,576	10,289	12,643	12,266	8,972

11a(v): Asset Relocations

*Project or programme** / $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
Customer requested relocations	350	608	490	490	490	490
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	350	608	490	490	490	490
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	350	608	490	490	490	490

11a(vi): Quality of Supply

*Project or programme** / $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
New ABS & automated devices	120	98	98	98	98	98
New RMUs	100	98	98	98	98	98
New Reclosers	300	98	98	98	98	98
New Comms site		78				
AMG upgrade		147				
SCADA pole top automation	50	49	98	98	98	98
**include additional rows if needed*	-					
All other projects or programmes - quality of supply	56		35	129	125	125
Quality of supply expenditure	626	569	427	522	518	518
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	626	569	427	522	518	518

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - legislative and regulatory							
Legislative and regulatory expenditure		-	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	-	-	-	-	-

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

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**		$000 (in constant prices)					
Abloy locks		100					
SCADA Mater station module		50					
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - other reliability, safety and environment		615	819	618	502	475	206
Other reliability, safety and environment expenditure		765	819	618	502	475	206
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		765	819	618	502	475	206

11a(ix): Non-Network Assets

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
Routine expenditure							
*Project or programme**		$000 (in constant prices)					
IT		957	649	620	430	474	396
Equipment		615	50	55	184	187	191
Vehicles		170	168	-	-	62	127
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - routine expenditure							
Routine expenditure		1,742	867	675	614	723	714
Atypical expenditure							
*Project or programme**							
Property		1,100	642				64
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - atypical expenditure							
Atypical expenditure		1,100	642	-	-	-	64
Expenditure on non-network assets		2,842	1,509	675	614	723	778

6.2 FORECAST OPERATIONAL EXPENDITURE – SCHEDULE 11B

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
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	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,785	2,142	2,185	2,229	2,273	2,319	2,365	2,412	2,460	2,510	2,560
11	Vegetation management	816	849	866	883	901	919	937	956	975	994	1,014
12	Routine and corrective maintenance and inspection	2,754	3,060	3,121	3,184	3,247	3,312	3,378	3,446	3,515	3,585	3,657
13	Asset replacement and renewal	714	306	312	318	325	331	338	345	351	359	366
14	**Network Opex**	6,069	6,357	6,484	6,613	6,746	6,881	7,018	7,159	7,302	7,448	7,597
15	System operations and network support	4,721	4,254	4,339	4,426	4,515	4,605	4,697	4,791	4,887	4,985	5,084
16	Business support	9,367	8,172	8,306	9,437	10,071	10,208	10,347	10,489	10,634	10,782	10,998
17	**Non-network opex**	14,088	12,426	12,645	13,863	14,586	14,813	15,044	15,280	15,521	15,767	16,082
18	**Operational expenditure**	20,157	18,783	19,129	20,476	21,332	21,694	22,062	22,439	22,823	23,215	23,679
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,785	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
23	Vegetation management	816	832	832	832	832	832	832	832	832	832	832
24	Routine and corrective maintenance and inspection	2,754	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
25	Asset replacement and renewal	714	300	300	300	300	300	300	300	300	300	300
26	**Network Opex**	6,069	6,232	6,232	6,232	6,232	6,232	6,232	6,232	6,232	6,232	6,232
27	System operations and network support	4,721	4,171	4,171	4,171	4,171	4,171	4,171	4,171	4,171	4,171	4,171
28	Business support	9,367	8,012	7,983	8,893	9,304	9,246	9,188	9,131	9,076	9,022	9,022
29	**Non-network opex**	14,088	12,182	12,154	13,063	13,475	13,417	13,359	13,302	13,247	13,193	13,193
30	**Operational expenditure**	20,157	18,414	18,386	19,295	19,707	19,649	19,591	19,534	19,479	19,425	19,425
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	249	249	249	249	249	249	249	249	249	249	249
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	42	85	129	173	219	265	312	360	410	460
43	Vegetation management	-	17	34	51	69	87	105	124	143	162	182
44	Routine and corrective maintenance and inspection	-	60	121	184	247	312	378	446	515	585	657
45	Asset replacement and renewal	-	6	12	18	25	31	38	45	51	59	66
46	**Network Opex**	-	125	252	381	514	649	786	927	1,070	1,216	1,365
47	System operations and network support	-	83	168	255	344	434	526	620	716	814	913
48	Business support	-	160	323	544	767	962	1,159	1,358	1,558	1,760	1,976
49	**Non-network opex**	-	244	491	800	1,111	1,396	1,685	1,978	2,274	2,574	2,889
50	**Operational expenditure**	-	368	743	1,181	1,625	2,045	2,472	2,904	3,344	3,790	4,254

6.3 FORECAST ASSET CONDITION - SCHEDULE 12A

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	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
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.			28.62%	38.53%	32.85%		3	-
11	All	Overhead Line	Wood poles	No.	16.71%	12.84%	23.13%	16.78%	22.84%	7.70%	3	6.00%
12	All	Overhead Line	Other pole types	No.								
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	2.15%	32.41%	26.59%	38.85%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km								
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	13.00%	87.00%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km								
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km								
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km								
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km								
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								
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	4.00%	-	32.00%	-	64.00%		4	4.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.								
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.					100.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	7.69%	11.54%	-	19.23%	61.54%		3	7.69%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	100.00%	-	4	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	18.10%	12.07%	6.90%	11.21%	51.72%	-	3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.								
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.								
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.					100.00%		4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	5.23%	-	5.23%	18.61%	70.93%	-	4	4.88%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.				50.00%	50.00%		3	-
35												

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.		3.45%	24.14%	17.24%	55.17%		4	7.40%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.10%	32.80%	23.40%	14.30%	29.40%	-	3	1.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km								
42	HV	Distribution Line	SWER conductor	km		100.00%					3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.30%	0.30%	3.60%	5.20%	90.60%	-	3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	73.00%	27.00%	-	3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km								
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	1.72%	-	6.90%	37.93%	53.45%	-	3	1.72%
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.	18.77%	6.09%	6.03%	19.02%	50.09%	-	2	6.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	10.00%	15.00%	75.00%	-	3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.87%	21.05%	26.32%	14.59%	35.17%	-	3	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.31%	31.40%	23.22%	26.20%	17.87%	-	3	1.31%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.17%	13.81%	20.04%	37.18%	27.80%	-	3	1.25%
53	HV	Distribution Transformer	Voltage regulators	No.			-	26.87%	73.13%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.								
55	LV	LV Line	LV OH Conductor	km	0.10%	4.00%	54.50%	34.10%	7.30%	-	2	1.00%
56	LV	LV Cable	LV UG Cable	km	0.09%	2.15%	21.15%	47.37%	29.24%	-	2	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km								
58	LV	Connections	OH/UG consumer service connections	No.								
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4.72%	-	6.88%	59.33%	29.07%		4	4.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	9.00%	1.00%	11.00%	79.00%		2	
61	All	Capacitor Banks	Capacitors including controls	No.	-	5.89%	11.76%	23.53%	58.82%		3	6.00%
62	All	Load Control	Centralised plant	Lot	8.00%	-	17.00%	25.00%	50.00%		3	8.00%
63	All	Load Control	Relays	No.	4.00%			20.00%	76.00%		2	
64	All	Civils	Cable Tunnels	km					100.00%		4	-

6.4 FORECAST CAPACITY – SCHEDULE 12B

Company Name **Alpine Energy Limited**

AMP Planning Period **1 April 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. 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

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
7	**12b(i): System Growth - Zone Substations**									
9	Albury (ABY)	4.55	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
10	Balmoral (BML)	#N/A	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
11	Bells Pond (BPD)	15.63	20.00	N-1	-	78%	20.00	1.27	Transformer	T1 installed FY18/19, T2 to be upgraded to relieve constraint
12	Clandeboye 1 (CD1)	14.18	20.00	N-1	-	71%	30.00	0.65	Transformer	Upgrade transformers to relieve constraint
13	Clandeboye 2 (CD2)	18.85	25.00	N-1	-	75%	25.00	0.88	No constraint within +5 years	Meets Alpine Security standard due to sufficient 11 kV backup
14	Cooney's Road (CNR)	4.14	-	N	1.8/0.8/0.6*	-	-	-	No constraint within +5 years	Meets Alpine security standard
15	Fairlie (FLE)	2.83	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
16	Geraldine (GLD)	6.40	-	N	-	-	7.50	0.95	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
17	Haldon Lilybank (HLB)	0.52	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
18	Pareora (PAR)	10.31	15.00	N-1	-	69%	15.00	0.74	No constraint within +5 years	Meets Alpine security standard
19	Pleasant Point (PLP)	5.00	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
20	Rangitata (RGA)	10.41	10.00	N-1	-	104%	10.00	1.10	Subtransmission circuit	Line capacity constraint, sufficient 11 kV backup in place
21	Studholme (STU)	14.12	10.00	N-1	-	141%	10.00	1.91	Transpower	Transpower two 11 MVA transformers, load shedding/shift required
22	Tekapo Village (TEK)	3.95	-	N	-	-	15.00	0.72	Subtransmission circuit	Options being assessed to upgrade installed firm capacity
23	Temuka (TMK)	13.71	25.00	N-1	-	55%	25.00	0.58	No constraint within +5 years	Meets Alpine Security standard
24	Timaru 11/33 kV (TIM)	17.37	25.00	N-1 Switched	-	69%	25.00	0.75	No constraint within +5 years	Meets Alpine Security standard
25	Twizel Village (TVS)	3.92	-	N	-	-	6.25	0.80	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
26	Unwin Hut (UHT)	0.99	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	
29	[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*									

6.5 FORECAST NETWORK DEMAND – SCHEDULE 12C

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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**						
8		*Number of ICPs connected in year by consumer type*				**Number of connections**		
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11		*Consumer types defined by EDB**						
12		Low Charge	11,249	11,351	11,454	11,558	11,663	11,769
13		Low Uncontrolled	45	46	46	47	47	48
14		015	18,997	19,169	19,343	19,519	19,696	19,874
15		015 Uncontrolled	76	77	78	78	79	80
16		360	1,259	1,270	1,282	1,293	1,305	1,317
17		360 Uncontrolled	29	30	30	30	30	31
18		Assessed	1,694	1,709	1,725	1,740	1,756	1,772
19		TOU 400V	141	143	144	145	146	148
20		TOU 11kV	10	10	10	10	10	11
21		IND	12	12	12	12	13	13
22		**Connections total**	33,513	33,817	34,124	34,433	34,746	35,061
23		**include additional rows if needed*						
24		**Distributed generation**						
25		Number of connections	428	494	559	624	689	754
26		Capacity of distributed generation installed in year (MVA)	2	2	3	3	3	4
27		**12c(ii) System Demand**						
28			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
29		**Maximum coincident system demand (MW)** for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
30		GXP demand	140	143	145	148	151	153
31	*plus*	Distributed generation output at HV and above	2	2	2	3	3	3
32		**Maximum coincident system demand**	142	145	148	150	153	156
33	*less*	Net transfers to (from) other EDBs at HV and above	-					
34		**Demand on system for supply to consumers' connection points**	142	145	148	150	153	156
35		**Electricity volumes carried (GWh)**						
36		Electricity supplied from GXPs	820	835	850	865	881	897
37	*less*	Electricity exports to GXPs	17	17	17	18	18	18
38	*plus*	Electricity supplied from distributed generation	29	30	30	31	31	32
39	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
40		**Electricity entering system for supply to ICPs**	832	847	863	878	894	910
41	*less*	Total energy delivered to ICPs	809	824	839	854	869	885
42		**Losses**	23	23	24	24	25	25
43								
44		**Load factor**	67%	67%	67%	67%	67%	67%
45		**Loss ratio**	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%

6.6 FORECAST INTERRUPTION DURATION – SCHEDULE 12D

Company Name	**Alpine Energy Limited**
AMP Planning Period	**1 April 2020 – 31 March 2030**
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							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	28.0	55.0	55.0	55.0	55.0	55.0
12	Class C (unplanned interruptions on the network)	95.2	91.9	91.9	91.9	91.9	91.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.20	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	0.73	1.20	1.20	1.20	1.20	1.20