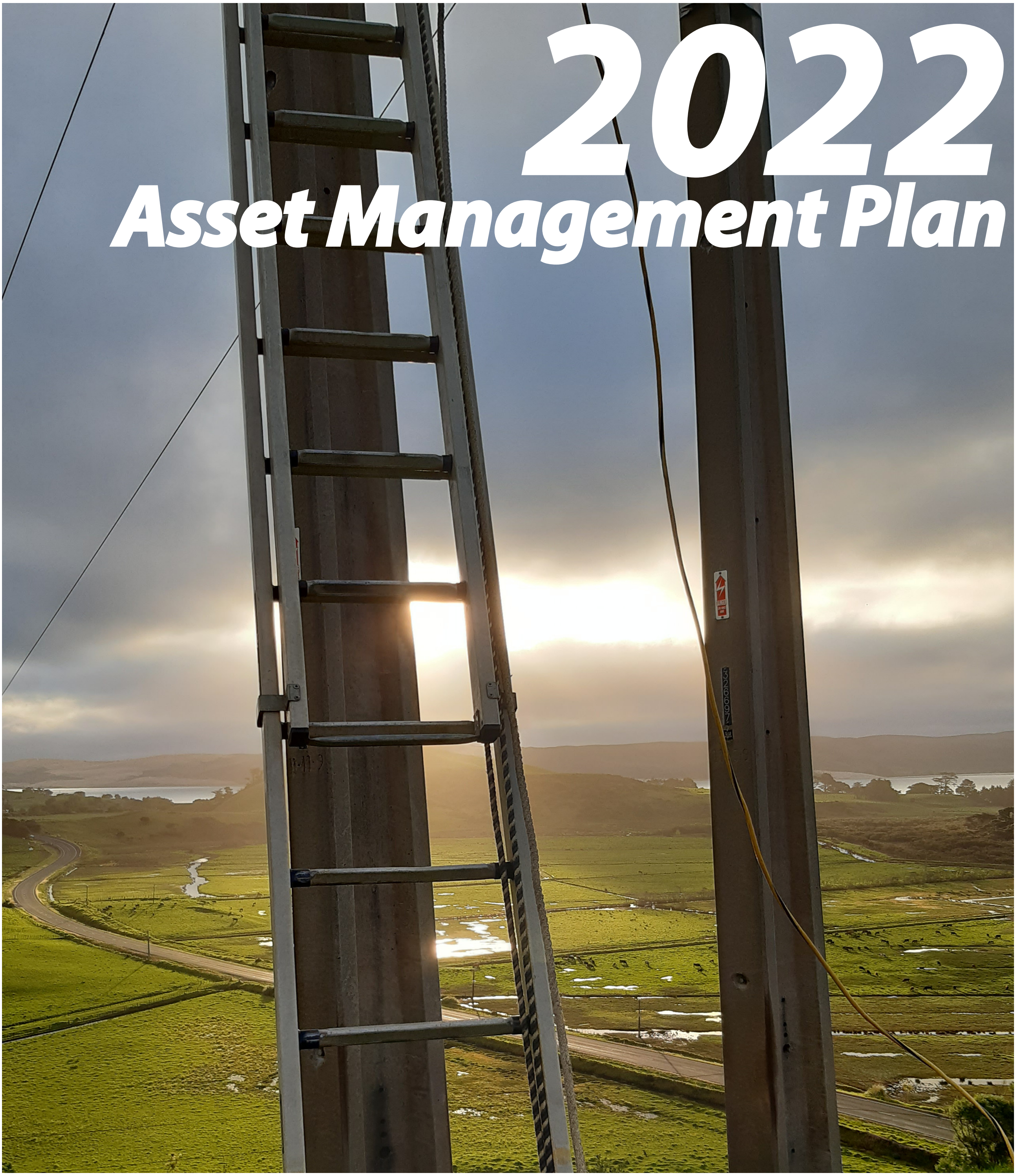
2022
Asset Management Plan



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TOP ENERGY®
TePuna Hihiko

Introduction

It gives me great pleasure to present Top Energy's 2022 Network Asset Management Plan (AMP) Update. Our AMP is prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and is the core asset management and operations plan for our electricity transmission and distribution network. It sets out our planned asset inspection, maintenance, development and replacement strategies, and the targeted service levels that we are planning to provide our consumers. This AMP Update should be read in conjunction with our comprehensive 2021 AMP which, except where modified by this Update, still underpins our asset management strategy. The regulatory schedules in Appendix 1 of this Update have been updated to cover the planning period 1 April 2022 to 31 March 2032, and replace the corresponding schedules in the 2021 AMP.

Notwithstanding the impact of Covid-19, we expect to deliver a record 337GWh of electricity in FYE 2022, to consumers connected to our network, up from 318GWh in FYE 2021. Our peak network demand was also a record 77MW, a marginal increase on the 76MW peak demand last year that was well above the stagnant 70MW peak demand disclosed in prior years. This suggests an upturn in the demand for electricity across our network, which has been subdued since 2010. This upturn is also reflected in the number of new consumers connecting to our network. By the end of FYE 2022, we expect to have connected 550 new consumers to our network, a 20% increase on the 460 new connections we have typically added in previous years.

The fourth generating unit (OEC4) at Ngawha Generation's geothermal station is now in full commercial operation. In FYE 2022 Ngawha is expected to generate 446GWh, of which 101GWh will be exported south. Nevertheless, Top Energy still needs to import energy over winter at times when the peak network demand exceeds the 57MW capacity of the Ngawha power station. This year our energy imports were only 22GWh so Ngawha will have supplied 94% of the energy supplied to consumers connected to our network.

In contrast to the subdued growth in demand over the whole network since 2010, localised electricity consumption in the Kerikeri and Whangaora areas has increased by more than 20% over the same period, and growth in this area continues apace. In the coming year we plan to start construction on a new 110kV substation at Wiroa to provide the network capacity needed to accommodate this growth. This will involve increasing the voltage on our Kaikohe Wiroa line to its full 110kV design capacity.

Our Board has approved a Strategy Map for the Top Energy Group, which sets out the Group's mission, vision, and values, and underpins everything that we do. Each operating division within the Group has developed its own strategic vision, which interprets the Group's mission and vision for the business unit's activities and delivers on the Group's core values and high-level corporate objectives.

Top Energy Network's mission is: *To provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.* Its vision is to: *Enable consumers to take greater control over their business and home energy supply needs by developing secure; two-way energy flow; load information and management solutions.*

Our ten-year asset management strategy through to FYE 2032 has been developed in accordance with this mission and vision and, being mindful of our corporate values and objectives, has addressed a range of strategic challenges. These include:

- *Providing a secure supply to the North*. We have installed sufficient diesel generation in the Kaitaia area to supply all small-use consumers during maintenance shutdowns of the 110kV Kaikohe-Kaitaia line. This is an interim solution as diesel generators have high greenhouse gas emissions, high maintenance requirements and a limited life. When construction of our new 110kV circuit between Wiroa and Kaitaia is completed in FYE 2030, supply to the north will become fully secure and we will be able to supply consumers in the Far North with renewable energy sourced from Ngawha under all reasonable network contingencies.
- *Improvement in supply reliability.* Our network development plan, which we initiated in FYE 2010, has significantly improved the reliability of the supply we provide our consumers. Apart from the new 110kV line into Kaitaia and the imminent new Wiroa 110kV substation, development of our transmission and subtransmission network is complete. Our reliability improvement initiatives are therefore focusing on our 11kV distribution network. Our new zone substations at Kerikeri and Kaeo have improved the reliability of the 11kV network in these areas by enabling shorter feeders with fewer connected consumers. Much of the remainder of our network is characterised by long 11kV feeders. Significant reliability improvements to this part of our network would require the construction of more zone substations, so that individual

feeders would be shorter, and less fault exposed. Such investment is difficult to justify, especially in areas where the network is already uneconomic. Going forward, our reliability improvement plan is therefore focused on incremental improvements to our existing 11kV infrastructure, without radically changing its architecture. While we expect this investment to further improve the reliability of supply we provide, the rate at which this improvement can be achieved is likely to be incremental.

- *Utility-scale photovoltaic generation.* A very exciting recent development has been the interest in the connection of new utility scale solar farms to our network. The average sunshine hours in many parts of our supply area are very high, making our area very attractive for solar farm development. We have now signed connection agreements with three solar farm developers for the connection of a total of 63MW of generation in the Kaitaia and Pukenui areas and for the connection of a further 9MW at a site close to the Ngawha power station. We are anticipating that the construction of some of these projects will commence during the FYE 2023 year.
- *Maintenance.* We have transitioned from a largely age-based process for prioritising maintenance and asset renewals to one based on the use of industry-standard asset health indicators. Asset health is a function of asset condition, determined by our asset inspection programme. In developing our defect management and asset replacement plans, we also consider asset criticality, which reflects the consequences of an in-service asset failure. This leads to better targeting of our maintenance expenditure.
- *Meeting the challenges of new technology.* We have installed an Advanced Distribution Management System (ADMS) that uses the latest available technology. This has significantly increased the level of automation in our management of network outages and increased worker and public safety by reducing the risk of operator error. It will also be used to optimise the use of our diesel generation. Over time, the system is capable of being further developed to ensure that we are well positioned to embrace emerging technologies that are starting to change the face of our industry, for the benefit of all our stakeholders.

Our response to these and other challenges is further described in our corporate video, *Top Energy – Energy of the Future* which can be viewed on our website http://www.topenergy.co.nz.

The Commerce Commission's price-quality path for the FYE 2021-25 regulatory period imposes a revenue cap, rather than a price cap, which provides us with more certainty that we will have the resources to implement our asset management plans. It has also relaxed constraints on the impact of planned interruptions, which gives us more flexibility in planning maintenance work on the 11kV network. While we are now at the point where we do not need to interrupt supply to undertake maintenance work on our 33kV networks, we still need to interrupt supply to localised areas when undertaking 11kV network maintenance. Consumers have advance warning of planned interruptions so they can minimise the impact of these disruptions.

Uncertainty remains in other components of the regulatory environment. In particular:

- The Electricity Authority has granted us an exemption from the cross-ownership requirements of the Electricity Industry Act 2010, which allows us to run the installed generation across the northern part of our network. This exemption is for five years, after which we will need to again test the market to determine whether the service can be provided by an external party. The new solar farms are unable to provide this service, as they only generate when the sun is shining and cannot be dispatched at other times.
- The Electricity Authority has finalized its review of transmission pricing. When implemented in 2023, transmission prices for consumers in the north of the country will increase significantly. The expanded Ngawha power station will reduce the extent that electricity consumed in our supply area is generated south of Auckland and we are disappointed that this will not protect our consumers from much of this increase. The increase is expected to be 350% of this year's transmission pricing. Most of this increase is due to a decrease this year of 65% due to Ngawha Generation commissioning OEC4 in FYE 2020.
- The Electricity Authority is also requiring electricity distribution businesses to develop more cost reflective pricing policies. We have introduced time-of-use tariffs, but these are not being passed on to consumer by retailers. We have also introduced a tariff of 0.5 cents per kWh of power injected into the low voltage network by small-scale photovoltaic generators to help us understand and mitigate the technical problems we anticipate will emerge as the penetration of this generation increases. This is proving a significant problem in Australia. We already have the highest penetration of small-scale photovoltaic generation of any New Zealand EDB and this penetration is increasing faster than anywhere else in the country. The concentration of this generation along our eastern seaboard exacerbates this issue.

- Industry response to the challenge of emerging technologies remains a source of debate, focused largely on the extent to which EDBs can recover the costs on implementing new technologies from regulated revenue. The FYE 2021-25 price-quality path decision has done little to clarify this issue.

We will keep a watching brief on these developments and their potential impact on our consumers and provide updates in subsequent AMPs.

In addition to the management of our network assets, we continue to develop the safety and asset management culture within Top Energy. We actively participate in industry safety initiatives, which require staff engagement at all levels and have the added benefit of sharing participants' experiences from across the industry. To succeed, the Company and all staff must maintain a proactive role in training, competency, peer support and guidance, and monitoring industry issues.

We hope that you find that this AMP Update shows that we continue to exercise prudent stewardship of our network assets for the long-term benefit of all our stakeholders and, in particular, the electricity consumers who rely on our network to meet their energy needs. We welcome your feedback on our asset management plans, or on any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://www.topenergy.co.nz/contact-us-feedback.shtml or emailed to info@topenergy.co.nz.

Russell Shaw

Chief Executive, Top Energy Ltd

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Executive Summary

Purpose

This AMP Update documents changes to the asset management strategies set out in our 2021 AMP. Furthermore, it records the outcome of an internal review that confirms that: (i) apart from the documented changes; the network development plan set out in the 2021 AMP remains appropriately aligned with our internal targets for improving our network reliability: and (ii) our network maintenance strategies will ensure that our network assets remain fit for purpose.

Expenditure Forecasts

We are currently experiencing significant increases in the cost of materials and labour and have increased our forecast capital and operational expenditures to take these into account. We have also increased our FYE 2023 capital expenditure forecast to provide for the connection of new solar farms, although these costs will be funded through capital contributions from the developers.

Our FYE 2023 capital expenditure is therefore forecast to be $17.8 million. This is 17% higher than the corresponding forecast in our 2021 AMP. Nevertheless, due to our work capacity availability, we have deferred some of the work in the FYE 2023 work plan that was set out in our 2021 AMP. These deferrals have been selected using a risk management assessment and do not include the construction of the new 110KV substation at Wiroa and the provision of a second 11kV feeder to supply the Russell peninsula.

Supply Reliability

Our internal supply reliability targets for unplanned interruptions shown in Section 2 are unchanged from the targets set out in our 2021 AMP. They are well below the quality thresholds set by the Commerce Commission as they incorporate the reliability improvements that have resulted from the network development plan that we have been implementing since FYE 2011.

This year we commissioned an external report into strategies for managing and improving the reliability of our network. Some of the recommendations of this review, such as the installation of additional feeders, come with a high cost that is difficult to justify. Nevertheless, we are implementing improvements to our fault management processes and will progressively implement other lower cost recommendations. However, we anticipate that these measures will only lead to incremental improvements in our overall network reliability.

Network Development

Utility Scale Solar Generation

Interest in the connection of utility scale solar farms to our network has been higher than anticipated in the 2021 AMP and we have signed connection agreements with four solar farm developers for a total connected capacity of 63MW, of which 54MW is to be constructed in the Kaitaia and Pukenui areas. In the short term we are unable to accommodate additional generation in the northern area due to the limited capacity of our 110kV Kaikohe-Kaitaia line.

The total amount of generation that can be connected to our network is also constrained by the capacity of the double circuit connection to the grid at Maungatapere. At present the power transfer across this link is limited to the capacity of one circuit due to a need to maintain supply in the event of a fault. There is less justification for this N-1 strategy now that most of our consumers' electricity is generated within our supply area and the link is now primarily used for export. We therefore asked Transpower to investigate the implementation of a run-back protection scheme that will allow the capacity of both circuits be fully utilised. In the event of a fault on one circuit, the output of generators within our supply area would be "run-back" to ensure that the capacity of the remaining circuit was not exceeded.

Management of System Operations

In 2021, we commissioned an external gap analysis of our capacity to manage a network where the amount of all types of generation connected across our network exceeded the total connected consumer demand by a significant margin. The consultant recommended we engage a Distribution System Operations Manager with experience in generation management, as well as additional engineering +and data analysis resource. The Board has accepted this recommendation and provision has been made for these new appointments in our updated operational expenditure forecasts.

Network Capacity Constraints

We have moved our mobile substation to Taipa to address the transformer constraint identified in the 2021 AMP. As the likelihood of the substation being required at other locations had been reduced by the installation of generation at Pukenui and Omanaia, we see this as a medium-term mitigation strategy that will endure until the planned new 110/11kV substation is constructed in the 2030s. In the unlikely event that the mobile substation has to be relocated away from Taipa, we can manage the load on the existing transformer at times of peak demand through the use of local generation and transferring small amounts of load to the Kaeo and NPL substations.

In the coming year (FY 2023) we are also planning to commence construction of the 110/33kV Wiroa substation, to provide the network capacity required to accommodate the demand growth in the Kerikeri, Waipapa and Whangaroa areas.

Lifecycle Asset Management

We have reviewed the failure rate of our SWER conductors and determined that our previous assumption of a 60-year useful life was overly conservative and a 70-year life more closely aligns with the number of conductor breakages faults that we are experiencing. This indicates that the conductor replacement component of our capital expenditure forecast is sufficient to ensure that these assets remain fit for purpose.

1. Asset Management Strategy and Delivery

We strive to continually improve how we achieve our strategic business objectives, while at the same time complying with all relevant legislation and providing a safe working environment for our staff. Nevertheless, there are no material changes to the Asset Management Maturity Assessment (AMMAT) presented in Schedule 13 of our 2021 AMP. We have therefore not included a revised schedule in this AMP Update.

This AMP Update covers the ten-year planning period 1 April 2022 to 31 March 2032 and was approved by our Board of Directors on 29 March 2022.

In the current year (FYE 2022) we have undertaken the following significant capital expenditure projects:

- Replacing the overhead 11kV switchyard at Waipapa substation with underground cables and ground-mounted switchgear to improve personnel safety.
- Installation of an 11kV underground cable between Okiato Point and the Rawhiti spur connection point as the first stage of a project to provide a second feeder to supply the Russell peninsula.
- Refurbishment of the Kaikohe-Kawakawa 33kV line.
- Crossarm replacements on the Kawakawa – Haruru line.
- Pole replacements in the Te Haumi estuary.
- Reconductoring part of the Rawene feeder.
- Refurbishment of the Tokerau feeder.
- Implementation of remote control of the newly installed diesel generators.

Notwithstanding these accomplishments, there are some capital projects and programmes in our current FYE 2022 workplan that will not be completed by the end of the FYE 2022 financial year. This work, with a total estimated cost of $2.38 million (in FYE 2022 prices) has been carried forward to FYE 2023.

Our forecast capital expenditure on network assets in the 2021 AMP was $15.6 million in FYE 2023 prices. This forecast did not include the carry forward from FYE 2022 discussed above and did not provide for the increase in materials and labour costs we are currently experiencing. To allow for these adjustments we have increased our forecast FYE 2023 capital expenditure on network assets to $17.8 million. This level of expenditure is significantly higher than our 2021 AMP forecast. As well, we have deferred some planned work to match anticipated work capacity availability. The projects and programmes to be deferred have been selected using a risk management assessment and are shown in Table 1.1 below. The construction of the new 110kV substation at Wiroa and the provision of a second 11kV feeder to supply the Russell peninsula have not been deferred.

Project	**Risk Assessment**
Remove ground fault neutralizer at Okahu Rd	This asset has been decommissioned and can be left in place with no impact on network performance.
Matauri Bay – Whangaroa feeder interconnection.	This project was initiated before the Kaeo substation was constructed when both feeders were supplied from Waipapa. With the construction of the new Kaeo substation, both feeders are now shorter and have fewer connected consumers. In FYE 2021 the combined SAIDI of the two feeders was only 3.92 SAIDI minutes, 1.3% of our total normalized network SAIDI of 300.83. Deferral of this project will not have a material impact on our total network reliability.

Project	Risk Assessment
Capacitor replacement programme	Capacitors are installed to manage power factor and are not operationally critical. We have 45 capacitors on our network. While five of these capacitors fleet are considered to be at end of life, the consequence of failure is considered low. There is a backlog of two replacements. This has been carried forward and remains in the FYE 2023 work plan. The replacement of a third capacitor in FYE 2023 has been deferred.
Wood pole replacements.	We have a long-term programme in place to replace all the wood poles on network. In FYE 2022 only half the budgeted number of wood poles were replaced under this programme. This backlog has been carried forward and remains on the FYE 2023 work plan. Replacement of further poles over and above this backlog has been deferred. The condition of all the wood poles on our network has been rigorously assessed through ultrasonic testing and in the 2021 AMP none were assessed as being at end of life. Deferral of these pole additional replacements should not pose a material increase in risk to safety or network performance. Wood poles replaced under this programme do not include the poles replaced under line remediation projects or under the defects management programme. These will still be replaced.
SCADA RTU replacements	Most RTUs are run to failure. While some RTUs are no longer supported by the manufacturer, we have an inventory of spares in stock that we expect to last 10 years for substation units and 5 years for field devices. There is a significant carryover that is included in our FYE 2023 expenditure forecast and additional funding in the FYE 2023 capex forecast has therefore been deferred.
Transformer earth remediation	We have a testing programme in place to identify transformer earths that require remediation. There is a carryover from FYE 2022 that is sufficient to fund the identified remediation requirements in FYE 2023.
Upgrading of auto-links	Drop-out fuses are run to failure, or replaced when identified as defective through our asset inspection programme. We are currently evaluating alternative, more reliable devices to use in place of drop-out fuses on higher criticality assets. This provision is included to fund a proactive replacement programme once a suitable replacement asset is identified. The evaluation is not yet complete, and the proactive replacement programme has not commenced. There is a carryover from the FYE 2022 work plan and an additional provision is not required.

Table 1.1: Deferred Projects and Programmes

Figure 1.1 compares our capital expenditure forecast for the planning period with that forecast in our 2021 AMP and Figure 1.2 provides a similar comparison for our forecast network operations and maintenance expenditure (excluding system operations and network support and business support expenditure). The increase in the forecast expenditure in FYE2023 reflects the high inflation we are currently experiencing. Furthermore, as discussed in Section 3 we have also adjusted the capital expenditure forecast to provide for the connection of new solar farms. While the potential connection of these farms was signalled in our 2021 AMP, development in this area has progressed rapidly over the current year to the point where we now expect up to four solar farms with a total capacity of 67MW to connect during FYE2023.

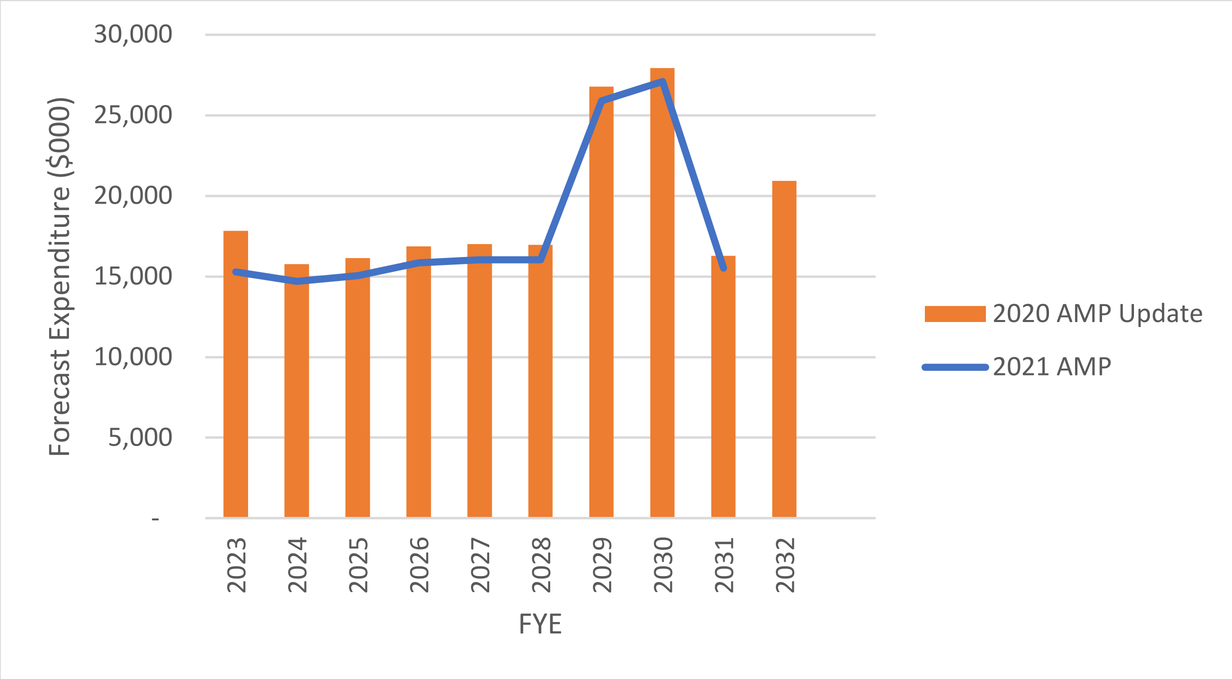

Figure 1.1: Comparison of Network Capital Expenditure Forecast with 2021 AMP (FYE 2023 constant prices)

FYE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2022 AMP Update	17,826	15,772	16,130	16,868	17,015	16,955	26,765	27,918	16,277	20,929
2021 AMP	15,293	14,702	15,059	15,847	16,044	16,044	25,894	27,097	15,506	

Table 1.1: Comparison of Network Capital Expenditure Forecast with 2021 AMP (FYE 2023 constant prices)

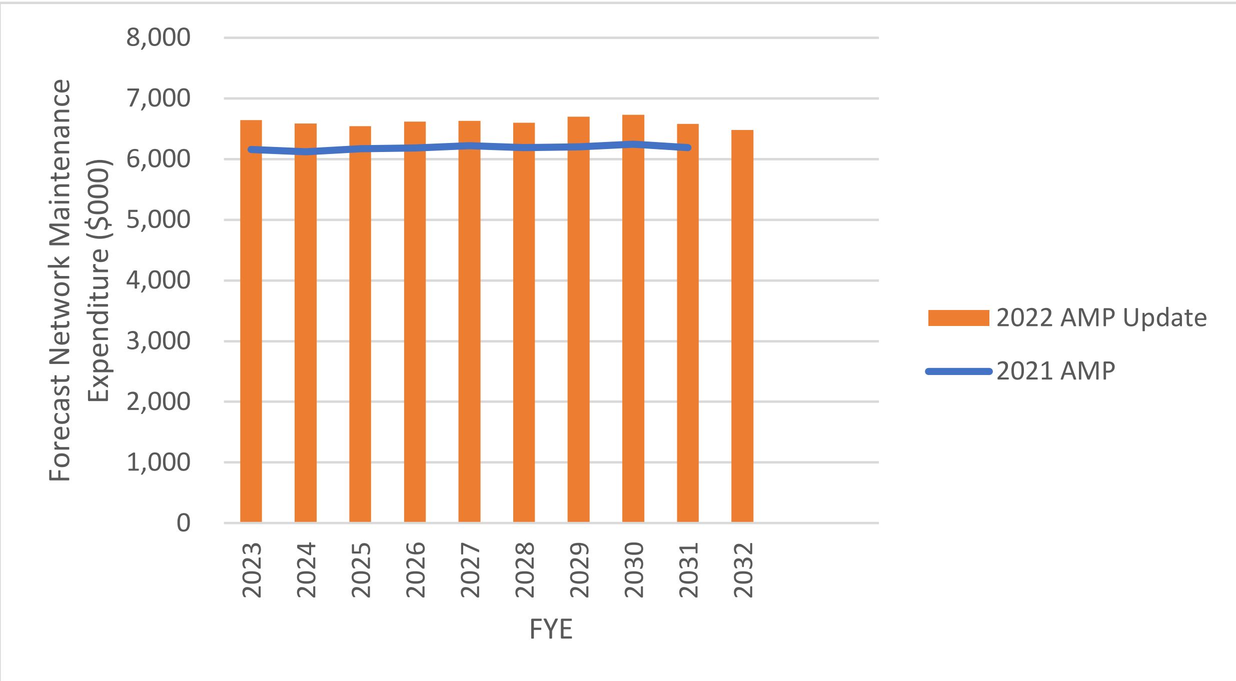

Figure 1.2: Comparison of Network Maintenance Expenditure Forecast with 2021 AMP (FYE 2023 constant prices)

FYE	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2022 AMP Update	6,646	6,588	6,542	6,620	6,631	6,600	6,701	6,732	6,581	6,482
2021 AMP	6,158	6,124	6,171	6,183	6,223	6,187	6,202	6,245	6,187	

Table 1.2: Comparison of Network Maintenance Expenditure Forecast with 2021 AMP (FYE 2023 constant prices)

2. Supply Reliability

2.1 Unplanned Interruptions

Our internal normalised SAIDI and SAIFI targets for unplanned interruptions over the planning period have not changed from the 2021 AMP and are compared with our historical performance in Figures 2.1 and 2.2.

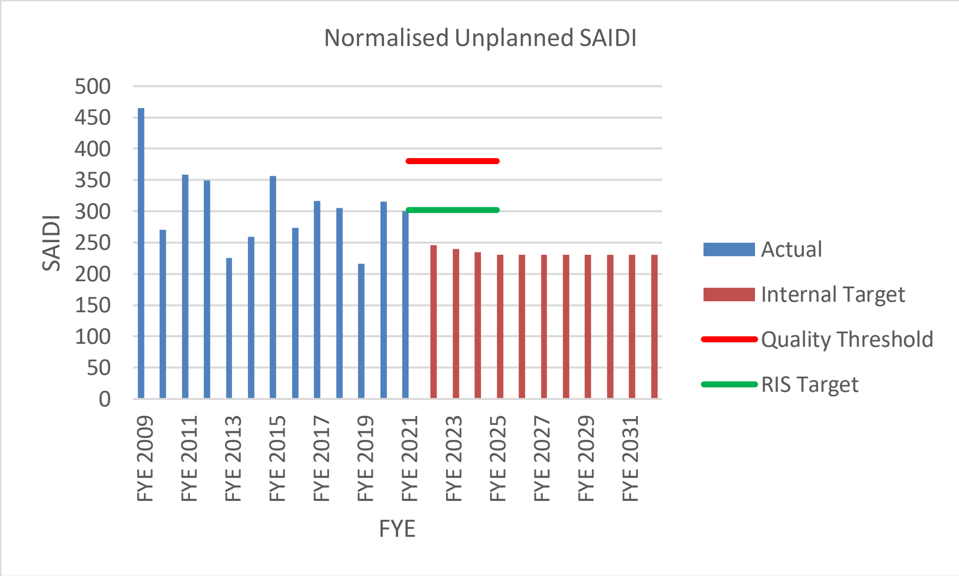

Figure 2.1: Normalised Unplanned SAIDI Targets

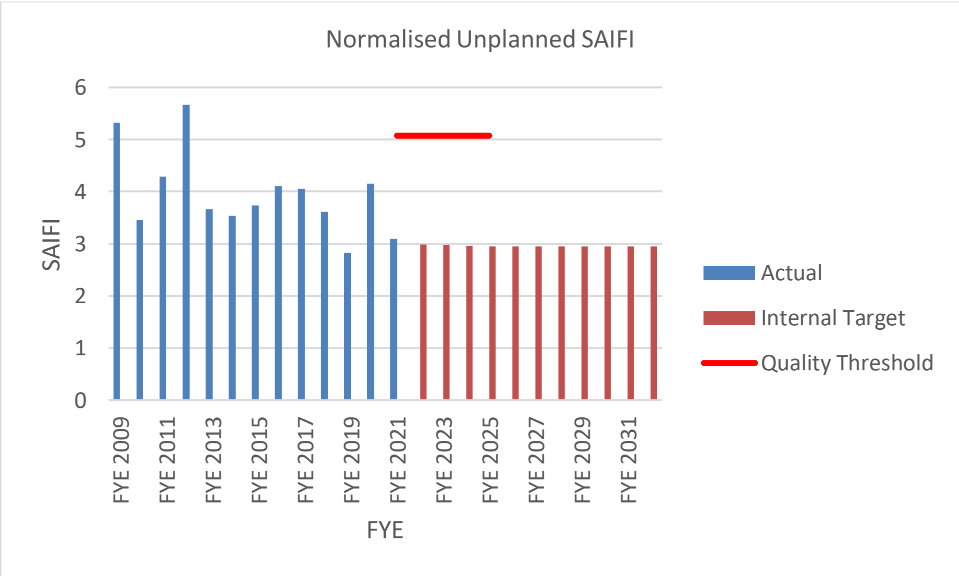

Figure 2.2: Normalised Unplanned SAIFI Targets

Our internal targets are much lower than the Commerce Commission's quality thresholds and, in the case of SAIDI, the current reliability incentive scheme (RIS) target[1], to reflect the expected outcomes of the network development plan we initiated in FYE2010. This plan has largely focused on improving the reliability of our transmission and

[1] The SAIDI RIS target reflects the average reliability of our network over the period FYE2010-19, after normalisation in accordance with the Commission's current price-quality path normalisation methodology. There is no SAIFI RIS target as the current RIS scheme does not include SAIFI.

subtransmission network through the installation of backup generation and the establishment of 33kV subtransmission ring circuits. It has also addressed the increasing electricity demand on our eastern seaboard through the installation of a new 33kV switching station at Wiroa and new 33/11kV zone substations at Kaeo and Kerikeri.

As at the end of February, we anticipate a FYE2022 normalised year-end SAIDI of around 348 minutes and a normalised SAIFI of around 4.5. While these outcomes are disappointing, in that they are significantly higher than our internal targets, they remain below our regulatory thresholds.

We have now reached a point where the reliability of our subtransmission network and the 11kV distribution network serving our eastern seaboard is very good. Our network SAIDI and SAIFI outcomes are dominated by faults on the 11kV distribution network serving the more remote rural areas to the west and north of our supply area. Supply to these areas is characterised by long 11kV feeders with a high fault exposure and high consumer numbers.

This year we commissioned an independent report into strategies for managing and improving the reliability of our network. Some of the recommended strategies, such as the installation of additional feeders come with a high cost that is difficult to justify for an area that is already uneconomic to serve. Our 2020 consumer survey also indicated that the price of electricity is more important to our consumers than reliability of supply. Nevertheless, we are implementing other recommendations such as the installation of additional line fault indicators, reclosers and sectionalisers, focussing on the poorer performing feeders. Unfortunately, these initiatives will only lead to incremental SAIDI improvements, since they have only localised impacts on a relatively large network. Some initiatives, such as line fault indicators, will reduce the time to locate and therefore repair a fault, thereby reducing SAIDI, but will not prevent the fault occurring. These initiatives have no impact on SAIFI.

We have also implemented short-term actions to improve the way we respond to faults immediately after they occur. These include:

- Utilising staff already working in the field during normal working hours to assist with fault location and repair, provided it is possible to leave the worksite in a safe condition. Field crews working on planned shutdowns are now be expected to release staff to assist with fault location and restoration.
- After hours, calling in the rostered technician to assist with fault location when required.
- Including vegetation staff in the on-call field staff roster.
- Prioritising the repair of defective switches and protection devices in the field.
- Prioritising the repair of faults on 11kV feeder backbones over spur or end of line faults and faults on the low voltage network.
- Where practical, reducing the faulted area by opening jumpers or cutting in line breaks, rather than only using existing isolation points.
- Escalating the fault response to call in additional responders to reduce the time to repair a fault.

3. Network Development

3.1 Network Development Achievements

We commenced our network development plan in FYE 2010 with the objective of improving the reliability of supply to consumers and increasing the capacity of the network to meet the high rate of growth in demand on the eastern seaboard of our network, particularly around the Kerikeri area. A key focus of the initiative was improving the security of supply to Kaitaia and our northern area, where supply was being interrupted for up to nine hours on one Sunday each year for planned maintenance of the 110kV Kaikohe Kaitaia line. Since the programme was initiated, we have invested $233 million (nominal) on the development of our network.

Under our network development programme, our achievements include:

- We have increased the capacity of the network supplying the Kerikeri and Whangaroa areas by the construction of a new 110kV line between Kaikohe and Wiroa. This line is currently operating at 33kV, but the operating voltage will be increased to 110kV when a new transmission substation at Wiroa is energized in FYE2024.
- We have successfully negotiated the required easements with the majority of property owners over our planned route of a new 110kV line between Wiroa and Kaitaia. Unfortunately, we were unable to reach agreement with a small number of property owners along the route but were granted ministerial approval to compulsorily acquire the easements. Two of these property owners have appealed this ministerial decision to the Supreme Court and we await the outcome of this case.
- We have installed a total of 16.4MW of diesel generation to provide a backup supply when the Kaikohe-Kaitaia 110kV line and our single circuit subtransmission lines are not in service. These generators are located at a new generator farm at Bonnetts Rd, west of Kaitaia, our Kaitaia construction and maintenance depot and at the Taipa, Pukenui and Omanaia zone substations. This has eliminated the need for planned supply interruptions for 110kV line maintenance and enabled supply to be restored after an unplanned interruption without waiting for the line to be repaired.
- We have upgraded the protection on our 33kV subtransmission network. This has allowed most of our subtransmission lines to be run in parallel or in a ring configuration so that most faults on our subtransmission network no longer cause a supply interruption.
- We have installed 33/11kV substations at Kerikeri and Kaeo to increase the capacity of the 11kV distribution network supplying these areas. This has increased the number of feeders in these areas, which has reduced the length and number of consumers on each feeder. This has improved the reliability of supply as fewer consumers are impacted by a fault.

3.2 Utility Scale Solar Farms

We have signed agreements for the connection of the following solar farms in the northern part of our network. The cost of the connection assets needed to connect these farms to our network will be paid by the developers and are included in our expenditure forecast as consumer connection capital expenditure.

3.2.1 Far North Solar Farm

A 16MW solar farm located adjacent to our Pukenui zone substation. It will be connected to the substation via an underground 33kV cable.

3.2.2 Pamapuria Solar Farm

A 24MW solar farm located approximately 2.6km southeast of our Kaitaia 11kV substation. It will be connected to the Kaitaia 33kV substation bus via a new single circuit line running alongside SH1.

3.2.3 Te Ahu Solar Farm

This solar farm, which has been developed by Loadstone Energy, will be a 23MW installation located approximately 3.6km northwest of Yuken Nissho Triboard Mill north of Kaitaia. It will be connected to our NPL substation at the mill site via a 33kV circuit comprised of a 2.8km overhead line and 0.9km underground cable.

3.2.4 Ngawha Solar Farm

We have also received a firm application to connect a 9MW solar farm at a site close to the Ngawha geothermal power station. We have commissioned a feasibility study for this new connection but, given that the external studies undertaken for the three new solar farms in our northern area have not uncovered any significant issues, we are not anticipating any problems.

To date, none of these developers have committed to the construction of the assets required to connect the solar farms to the network. Nevertheless, based on our discussions with the project developers we expect at least one, and probably more, of these four projects to move forward in FYE 2023.

3.3 Transmission Line Constraints

3.3.1 Kaitaia-Kaikohe Single-Circuit Transmission Line

In Section 5.11.2.2 of our 2021 AMP, we noted that the summer rating of this line was 55MVA and that the minimum demand in the northern area was 10.4MVA. This limits the maximum amount of solar generation that we can connect in our northern area, given that the output of a solar farm peaks over the summer. As the aggregate capacity of the three solar farms for which we have already signed connection agreements is 63MVA, we are unable to sign additional agreements for the connection of solar farms in our northern area. Commissioning of the planned Wiroa-Kaitaia line, currently scheduled for FYE 2030, will mitigate this constraint.

3.3.2 Kaikohe-Maungatapere Double Circuit Transmission Line

This constraint was discussed in Section 5.11.2.1 of our 2021 AMP, where we noted that the maximum amount of utility-scale generation that could feed into our network on summer days was 91.3MVA due to the 63MVA rating of Transpower's Kaikohe-Maungatapere 110kV transmission line. The 63MVA of solar generation to be connected in our northern area, together with the 57MVA generated by our Ngawha geothermal power station will exceed this.

The rating of the Kaikohe-Maungatapere transmission line is based on the thermal capacity of only one of the two circuits. Transpower operates this line with an N-1 level of security so that, if one circuit is out of service, there is no interruption to supply, as the full line load can be carried by the second circuit. This approach, which is consistent with good industry practice, is appropriate if the main purpose of the line is to import energy to supply consumers connected to our network since it avoids the need to interrupt supply to consumers when one circuit is out of service.[2]

If the amount of generation connected to our network exceeds the local demand and the line is used to export the surplus power south, the rationale for limiting the load on this line to the thermal capacity of one circuit is less compelling. This is because when one circuit is out of service the output of our local generation can be "run-back" to a level that ensures that the in-service circuit is not overloaded, without interrupting supply to our consumers. We have asked Transpower to investigate the implementation of a run-back scheme that would allow the thermal capacity of both circuits to be utilised. With this scheme implemented, when one of the Kaikohe-Maungatapere circuits is out of service and the load on the second circuit exceeds 90% of its rated thermal capacity, Transpower's protection system will provide an alarm to our ADMS/SCADA system which will automatically limit the output of the solar farms to ensure that the thermal rating of the in-service line is not exceeded.

3.4 Taipa Transformer Constraint

As signalled in the 2021 AMP, we have relocated our mobile substation to Taipa to mitigate the high load on the permanent 5/6.25MVA transformer at times of peak network demand. The mobile transformer was constructed in

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2 The N-1 winter rating of this circuit is 77MVA, which is higher than the summer rating because of the colder weather. Top Energy's disclosed peak network demand for FYE2021 was 76MVA so that, in the absence of Ngawha generation, the line would have been almost fully loaded if one circuit was out of service at times of peak demand.

2003 so that supply could be maintained at our single-transformer substations if there was a transformer failure or if the transformer was taken out of service for maintenance.

There are four single-transformer substations on our network: Taipa, Pukenui, Omanaia and Mt Pokaka. While the Taipa transformer is fully loaded at times of peak demand, the other three transformers are only moderately loaded, and the transformers at Mt Pokaka and Omanaia are both relatively new. Furthermore, backup generation has now been installed at both Pukenui and Omanaia and in the event of a transformer failure at Mt Pokaka, supply to all small use consumers would be quickly restored by transferring the load to other 11kV feeders.

Transformer failures are relatively rare, particularly where transformers are installed on networks like ours with low fault levels. In the unlikely event that the mobile substation needs to be relocated away from Taipa, the load on the Taipa transformers would be managed either by running the local backup generators or by transferring some load to other zone substations at times of peak demand. Peak demand is not continuous and only occurs over a small number of hours each year. Active management of the transformer load would only be necessary during these times.

The relocation of the mobile substation to Taipa has fully mitigated this constraint.

3.5 Decarbonisation Impacts

3.5.1 Network Demand

While our 2021 AMP has forecast relatively modest growth in demand through to FYE2030, this was based on recent growth rates and known drivers of future increases in consumption.[3] However, in its Whakamana i Te Mauri Hiko report[4] Transpower has predicted that electricity demand will increase 68% by 2050 due to decarbonisation of the economy through the electrification of both the transport fleet and the production of industrial heat. We have undertaken an internal review of the capacity of our network to deliver demand increases of the magnitude forecast by Transpower. This review concluded that:

- The increase in demand for electricity would vary across the country and therefore affect EDBs differently. It was likely that we would experience a demand increase lower than average since there are few industrial boilers in our supply area fired by fossil fuels.
- Nevertheless, increases in demand would be localized and there could be parts of our network where the demand increase was higher than Transpower's forecast. On this basis the review assumed that demand would increase by 20% by 2035 and would double by 2050.
- On completion of the Wiroa substation and the planned Wiroa-Kaitaia line, which are already provided for in our capex forecast, our transmission and subtransmission lines will have sufficient capacity to accommodate this demand increase. The one exception is the 33kV ring circuit supplying Haruru, Moerewa and Kawakawa. While the lines have sufficient thermal capacity, there would be a voltage constraint at the extremities during times of maximum demand if the ring is opened for any reason. The solution is a switching station at Oromahoe, together with voltage support at Haruru and Kawakawa. This is a relatively low-cost solution as new lines would not be required.
- Transformer capacity at the Kaikohe and Kaitaia transmission substations would need to be increased and larger transformers may need to be installed at some zone substations. In some cases, the additional capacity could be provided by fitting pumps and fans to existing units.
- Localised growth in demand could result in constraints on the 11kV distribution network. The review noted that studies into the network reinforcement required to supply a proposed new resort on the Karikari peninsula (which did not proceed) found that localized 1MW demand increase would require the addition of voltage regulators, a 2MW increase would require a feeder upgrade to 22kV and a 5MW increase would require a new 33kV line and substation. Similar development principles could be applied to other feeders

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3 The disclosed peak demand for FYE2021 was 75MW, 6% higher than expected. However, the total energy delivered was lower than expected due to the impact of Covid-19 lockdowns.

4 *Whakamana i Te Mauri Hiko – Empowering our Energy Future*, Transpower, March 2020

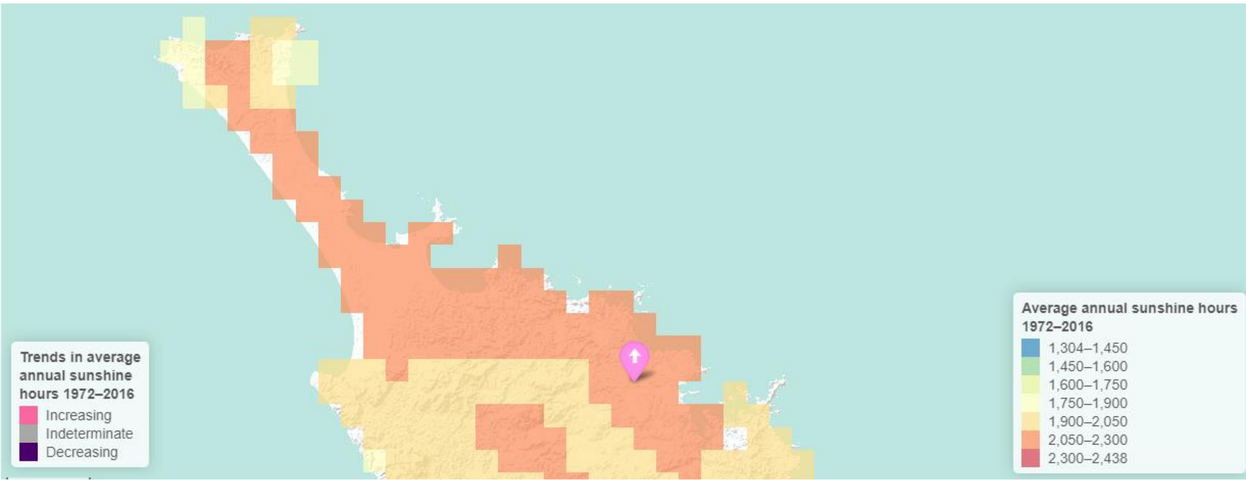
and growth scenarios on a case-by-case basis. It should be noted that much of the west of our supply area is supplied by long 11kV feeders with little subtransmission overbuild.

- The review concluded that ongoing development of the network to support the assumed increase in demand would not require levels of expenditure significantly higher than is now being budgeted for network development.

3.5.2 Renewable Energy Zone

If the increased demand for electricity forecast in Transpower's Whakamana i Te Mauri Hiko report is to be met, there will need to be significant investment in both wind and solar generation in New Zealand between now and 2050. As shown in Figure 3.1, the average sunshine hours in most of our supply area is very high making the region very attractive to solar farm developers. In addition to the four developments discussed in Section 3.2, which have all emerged within just two years, we have had a significant number of less formal enquiries from developers interested in connecting additional utility-scale solar generation farms to our network. Northpower is receiving similar enquiries and Transpower has also received enquiries from developers about the possibility of connecting solar farms in our supply area directly to the transmission grid. Unfortunately, the transmission network supplied from Transpower's Maungatapere substation does not have the capacity to accommodate the expected demand.

We have therefore formed a working group with Transpower and Northpower to investigate options to increase the capacity of the transmission network supplying this "renewable energy zone". The group operates at three levels – a steering group at CEO or senior executive level, a management group at network management level and a technical group at engineering level. The working group is focussed on how to get more capacity out of existing assets and the run-back scheme described in Section 3.3.2 is an example of this. Transpower is also investigating increasing the thermal capacity of the two Kaikohe-Maungatapere circuits by running the conductor at a higher temperature. This would increase the conductor sag when the line is fully loaded so some additional structures are likely to be required to ensure that the ground clearance of the conductors remains above the statutory minimum.



Source: Statistics NZ, (https://www.stats.govt.nz/indicators/sunshine-hours)

Figure 3.1: Sunshine Hours in Top Energy Supply Area

3.6 Solar Penetration

There has been continuing steady growth in the connection of small-scale solar generation to our network. As of 31 January 2022 there was a total of 7.07MW of small-scale solar generation connected to our network, an increase of 1.33MW (23%) over the previous 12 months. A total of 1,343 ICPs now have small scale solar systems installed, an increase of 206 (18%) over the same period. This equates to about 17 new connections each month with an average system size of 6.5kW.

3.7 Management of System Operations

The new solar farms, the ongoing increase in the amount of small-scale solar generation being connected to our network and the need to monitor the potential impact of emerging technologies on the development and operation of our network. has exposed a capability gap within our current network management resource. We therefore commissioned an external gap analysis of our capacity to manage a network where the amount of all types of generation connected across our network exceeded the total connected consumer demand by a significant margin. The consultant recommended we engage a Distribution System Operations Manager (DSOM), as well as additional engineering and data analysis resource. The DSOM will have a more strategic focus than our current Operations Manager role and will be responsible for the management of generator enquiries, scenario planning, system testing and operator training. We also plan to employ a new design/ delivery engineer, who will focus on SCADA/protection support as well as future technology infrastructure. An example of the later would be capturing potential efficiency gains from the utilisation of smart meter data and greater visibility of the low voltage network. Additional data analysis resource will be progressively brought on board to increase the capacity of our existing network data analysis team.

Our Board has generally accepted the recommendations of the external consultant and the cost of the new hires has been included in our expenditure forecasts.

4. Lifecycle Asset Management

4.1 Health Assessment of Conductor Fleet

For most asset categories our asset health assessment is based on the condition of individual assets as determined by visual inspection though our structured asset inspection programme or, in the case of larger more critical assets such as power transformers, routine testing. In the case of assets where it is not possible to accurately assess condition via visual inspection, we use age as a proxy for asset condition.

In assessing the health of our SWER conductors we have assumed a maximum asset life of 60 years, which suggests that approximately 13.5% of our SWER conductor is now at end of life and requiring replacement. However, an analysis of the conductor failures during FYE 2020 indicates the only 12% of conductor breakages are unassisted – in the remaining 88% of faults, the breakage was due to other factors including vegetation contact and trees falling onto the line. On this basis we believe that our previous assumption of a 60-year conductor asset life is unduly conservative and would lead to premature asset replacement. Our experience suggests that a 70-year asset life assumption is more realistic. A 70-year asset life implies that the health of our older conductors is better than indicated in the 2021 AMP and we are confident that the conductor replacement component of our capital expenditure forecast is sufficient to ensure that these assets remain fit for purpose.

5. Appendices

Appendix A – Asset Management Plan Schedules

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 14a	Mandatory Explanatory Notes on Forecast Information

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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

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		for year ended	**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**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	4,139	4,264	3,121	3,183	3,194	3,051	3,057	3,062	3,066	3,069	2,145
11		System growth	1,461	4,574	5,096	3,720	1,751	62	63	4,751	5,170	4,525	4,695
12		Asset replacement and renewal	4,896	6,575	6,052	6,952	6,806	8,038	8,000	7,347	7,956	9,068	14,553
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	769	859	1,288	2,926	6,149	7,267	5,424	14,981	15,060	1,101	3,619
16		Legislative and regulatory											
17		Other reliability, safety and environment	417	1,554	531	-	-	-	1,970	-	711	1,116	-
18		**Total reliability, safety and environment**	1,186	2,413	1,819	2,926	6,149	7,267	7,394	14,981	15,771	2,217	3,619
19		**Expenditure on network assets**	11,682	17,826	16,088	16,782	17,901	18,418	18,514	30,142	31,963	18,879	25,012
20		Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
21		**Expenditure on assets**	11,682	17,826	16,088	16,782	17,901	18,418	18,514	30,142	31,963	18,879	25,012
22													
23	*plus*	Cost of financing	94	100	102	106	113	122	135	250	745	150	156
24	*less*	Value of capital contributions	3,269	3,630	2,499	2,549	2,547	2,544	2,539	2,534	2,527	2,519	1,529
25	*plus*	Value of vested assets	5	5	5	5	5	6	6	6	6	6	6
26													
27		**Capital expenditure forecast**	8,512	14,301	13,696	14,344	15,472	16,002	16,116	27,864	30,187	16,516	23,645
28													
29		Assets commissioned	10,576	18,932	16,088	16,782	17,162	12,562	13,832	12,041	59,657	20,438	26,711

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*
31		for year ended	**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**	**31 Mar 31**	**31 Mar 32**
32			**$000 (in constant prices)**										
33		Consumer connection	4,139	4,264	3,060	3,060	3,010	2,819	2,769	2,719	2,669	2,619	1,795
34		System growth	1,461	4,574	4,996	3,576	1,650	57	57	4,219	4,501	3,862	3,928
35		Asset replacement and renewal	4,896	6,575	5,933	6,682	6,414	7,425	7,246	6,524	6,926	7,740	12,178
36		Asset relocations	-	-	-	-	-	-					
37		Reliability, safety and environment:											
38		Quality of supply	769	859	1,263	2,812	5,795	6,714	4,912	13,303	13,111	940	3,028
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	417	1,554	520	-	-	-	1,970	-	711	1,116	-
41		**Total reliability, safety and environment**	1,186	2,413	1,783	2,812	5,795	6,714	6,883	13,303	13,822	2,056	3,028
42		**Expenditure on network assets**	11,682	17,826	15,773	16,130	16,868	17,015	16,955	26,765	27,918	16,277	20,929
43		Expenditure on non-network assets	-	-	-	-	-	-					
44		**Expenditure on assets**	11,682	17,826	15,773	16,130	16,868	17,015	16,955	26,765	27,918	16,277	20,929
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											

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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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*
50												
51–52	for year ended	**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**	**31 Mar 31**	**31 Mar 32**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	61	124	184	232	288	343	397	450	350
55	System growth	-	-	100	144	101	5	6	532	669	663	766
56	Asset replacement and renewal	-	-	119	270	393	612	754	823	1,030	1,329	2,376
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	25	114	355	553	511	1,678	1,949	161	591
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	10	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	36	114	355	553	511	1,678	1,949	161	591
63	**Expenditure on network assets**	-	-	315	652	1,032	1,403	1,560	3,377	4,045	2,602	4,083
64	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**	-	-	315	652	1,032	1,403	1,560	3,377	4,045	2,602	4,083
66												

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
67	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	All types	4,139	4,264	3,060	3,060	3,010	2,819
71	[EDB consumer type]						
72	[EDB consumer type]						
73	[EDB consumer type]						
74	[EDB consumer type]						
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	4,139	4,264	3,060	3,060	3,010	2,819
77	*less* Capital contributions funding consumer connection	3,269	3,630	2,450	2,450	2,400	2,350
78	**Consumer connection less capital contributions**	870	634	610	610	610	469
79	**11a(iii): System Growth**						
80	Subtransmission	3	-	-	-	-	-
81	Zone substations	154	3,089	4,621	3,519	145	
82	Distribution and LV lines	1,304	1,252	375	57	1,092	57
83	Distribution and LV cables	-	-	-	-	-	-
84	Distribution substations and transformers	-	233			413	
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	-	-	-	-	-	-
87	**System growth expenditure**	1,461	4,574	4,996	3,576	1,650	57
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	1,461	4,574	4,996	3,576	1,650	57
90							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		1,545	2,455	938	1,284	939	944
95	Zone substations		479	76	72	194	74	76
96	Distribution and LV lines		2,050	2,666	3,352	3,683	4,051	5,045
97	Distribution and LV cables		97	127	121	122	123	124
98	Distribution substations and transformers		238	406	627	572	398	402
99	Distribution switchgear		468	664	695	698	701	706
100	Other network assets		19	180	129	129	129	129
101	**Asset replacement and renewal expenditure**		4,896	6,575	5,933	6,682	6,414	7,425
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		4,896	6,575	5,933	6,682	6,414	7,425
104								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	[Description of material project or programme]							
110	[Description of material project or programme]							
111	[Description of material project or programme]							
112	[Description of material project or programme]							
113	[Description of material project or programme]							
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations							
118	**Asset relocations less capital contributions**		-	-	-	-	-	-
119								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Property rights - 110kV Wiroa-Kaitaia line		310	28	27	-	-	-
125	Construction - 110kV Wiroa-Kaitaia line		-	-	-	696	5,410	5,187
126	Feeder interconnections		-	-	528	1,195	-	1,168
127	11kV network reliability improvement		151	628	511	887	350	324
128								
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply		308	203	198	35	35	35
131	**Quality of supply expenditure**		769	859	1,263	2,812	5,795	6,714
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		769	859	1,263	2,812	5,795	6,714
134								

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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)

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sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	[Description of material project or programme]						
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Miscellaneous small projects		1,554	520	-	-	-
154	Waipapa safety remediation	417					
155							
156							
	**include additional rows if needed*						
157	All other projects or programmes - other reliability, safety and environment						
158	**Other reliability, safety and environment expenditure**	417	1,554	520	-	-	-
159	*less* Capital contributions funding other reliability, safety and environment						
160	**Other reliability, safety and environment less capital contributions**	417	1,554	520	-	-	-
161							
162		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
163	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
164	**11a(ix): Non-Network Assets**						
165	**Routine expenditure**						
166	*Project or programme**	**$000 (in constant prices)**					
167	General						
168	[Description of material project or programme]						
169	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	**include additional rows if needed*						
173	All other projects or programmes - routine expenditure						
174	**Routine expenditure**	-	-	-	-	-	-
175	**Atypical expenditure**						
176	*Project or programme**						
177	ADMS Stage 2 Implementation						
178	GIS Software						
179	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	**include additional rows if needed*						
183	All other projects or programmes - atypical expenditure						
184	**Atypical expenditure**	-	-	-	-	-	-
185							
186	**Expenditure on non-network assets**	-	-	-	-	-	-
187							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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

		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 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**	**31 Mar 31**	**31 Mar 32**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,856	1,457	1,672	1,706	1,740	1,774	1,810	1,846	1,883	1,921	1,959
11	Vegetation management	1,807	1,923	1,962	2,001	2,041	2,082	2,123	2,166	2,209	2,253	2,298
12	Routine and corrective maintenance and inspection	2,182	2,190	2,175	2,171	2,297	2,354	2,368	2,529	2,615	2,490	2,422
13	Asset replacement and renewal	883	1,075	1,097	1,119	1,141	1,164	1,187	1,211	1,235	1,260	1,285
14	**Network Opex**	6,728	6,646	6,905	6,996	7,218	7,374	7,488	7,752	7,942	7,923	7,964
15	System operations and network support	5,673	6,331	6,492	6,585	6,789	7,001	7,224	7,457	7,702	7,923	8,190
16	Business support	6,412	6,925	7,064	7,208	7,357	7,513	7,674	7,841	8,016	8,196	8,382
17	**Non-network opex**	12,085	13,256	13,556	13,793	14,146	14,514	14,898	15,299	15,717	16,119	16,572
18	**Operational expenditure**	18,813	19,902	20,461	20,789	21,364	21,889	22,387	23,050	23,660	24,042	24,536

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 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**	**31 Mar 31**	**31 Mar 32**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,856	1,457	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639	1,639
23	Vegetation management	1,807	1,923	1,923	1,923	1,923	1,923	1,923	1,923	1,923	1,923	1,923
24	Routine and corrective maintenance and inspection	2,182	2,190	2,132	2,087	2,164	2,175	2,145	2,246	2,277	2,125	2,026
25	Asset replacement and renewal	883	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075
26	**Network Opex**	6,728	6,646	6,770	6,724	6,802	6,813	6,782	6,883	6,914	6,763	6,664
27	System operations and network support	5,673	6,331	6,365	6,329	6,397	6,468	6,543	6,622	6,705	6,762	6,853
28	Business support	6,412	6,925	6,925	6,928	6,933	6,941	6,951	6,963	6,978	6,995	7,014
29	**Non-network opex**	12,085	13,256	13,290	13,257	13,330	13,409	13,494	13,585	13,683	13,757	13,867
30	**Operational expenditure**	18,813	19,902	20,060	19,981	20,132	20,222	20,276	20,468	20,597	20,520	20,531
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	453	571	616	634	653	673	694	716	738	762	786

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 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**	**31 Mar 31**	**31 Mar 32**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	33	66	100	135	171	207	244	281	320
43	Vegetation management	-	-	38	78	118	159	200	243	286	330	375
44	Routine and corrective maintenance and inspection	-	-	43	84	132	179	223	283	339	365	395
45	Asset replacement and renewal	-	-	22	43	66	89	112	136	160	185	210
46	**Network Opex**	-	-	135	272	416	562	706	868	1,028	1,161	1,300
47	System operations and network support	-	-	127	256	392	533	681	835	997	1,161	1,337
48	Business support	-	-	139	280	424	572	723	878	1,038	1,201	1,368
49	**Non-network opex**	-	-	266	536	816	1,105	1,404	1,714	2,034	2,362	2,705
50	**Operational expenditure**	-	-	401	807	1,232	1,667	2,110	2,582	3,063	3,522	4,005

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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

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	**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.	0.02%	2.55%	8.49%	80.17%	4.87%	3.90%	4	1.29%
11	All	Overhead Line	Wood poles	No.	0.20%	12.80%	68.07%	2.79%	14.84%	1.29%	4	6.50%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	100.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.22%	15.77%	62.87%	16.14%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	83.58%	16.42%	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	9.09%	63.64%	27.27%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	6.67%	93.33%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	10.34%	60.34%	27.59%	1.72%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	0.59%	53.53%	44.12%	1.76%	4	-
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	28.57%	-	-	71.43%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	70.83%	29.17%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	13.51%	-	48.65%	35.14%	2.70%	4	-
35												

Company Name **Top Energy**
AMP Planning Period **1 April 2022 – 31 March 2032**

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.	-	2.08%	20.83%	58.33%	18.75%	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.13%	12.17%	27.06%	36.97%	20.67%	-	2	3.13%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	22.04%	23.85%	18.16%	19.55%	16.40%	-	2	11.02%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.29%	0.62%	23.67%	75.42%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	1.76%	12.43%	65.75%	20.06%	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	100.00%	-	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.27%	-	4.12%	78.30%	15.93%	1.37%	4	0.14%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7.50%	11.30%	13.72%	21.50%	44.70%	1.29%	2	7.50%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	0.11%	2.24%	9.61%	83.78%	4.26%	4	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	0.12%	2.00%	87.29%	6.00%	4.59%	4	-
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.08%	0.31%	11.85%	78.73%	6.40%	2.62%	4	0.20%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	10.53%	54.39%	35.08%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	25.00%	75.00%	-	-	4	-
55	LV	LV Line	LV OH Conductor	km	2.39%	8.48%	30.93%	42.64%	15.56%	-	2	2.39%
56	LV	LV Cable	LV UG Cable	km	0.29%	3.38%	18.50%	43.76%	34.07%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.80%	4.28%	21.34%	46.86%	26.72%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.02%	0.48%	15.04%	70.73%	8.70%	5.02%	4	0.25%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.50%	-	1.50%	29.25%	61.75%	-	4	7.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	4	N/A
61	All	Capacitor Banks	Capacitors including controls	No.	9.30%	2.33%	58.14%	20.93%	9.30%	-	4	5.81%
62	All	Load Control	Centralised plant	Lot	-	-	-	100.00%	-	-	4	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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

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

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
9	Kaikohe	10	17	N-1	1	57%	17	57%	No constraint within +5 years	
10	Kawakawa	7	6	N-1	3	109%	6	74%	No constraint within +5 years	1.5MW to be transferred to Haruru in FYE2022, after completion of Russell reinforcement project.
11	Moerewa	3	5	N-1	3	68%	5	68%	No constraint within +5 years	
12	Waipapa	10	23	N-1	8	42%	23	45%	No constraint within +5 years	
13	Omanaia	3	-	N-0	2	-	-	-	Transformer	Transfer capacity includes 2MW of onsite generation. Mobile transformer is available if needed.
14	Haruru	6	23	N-1	1	25%	23	34%	No constraint within +5 years	1.5MW to be transferred from Haruru in FYE2022
15	Mt Pokaka	3	-	N-0	2	-	-	-	Transformer	Mobile transformer available. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	8	23	N-1	6	33%	23	37%	No constraint within +5 years	
17	Kaeo	4	-	N-0	4	-	-	-	Subtransmission circuit	There will be only one incoming subtransmission circuit until the southern section of the 110kV line is completed, expected to be in FYE2030.
18	Okahu Rd	8	12	N-1	4	73%	12	77%	No constraint within +5 years	
19	Taipa	6	-	N-0	3	-	-	-	Subtransmission circuit	The trasnfer of the mobile substation to Taipa on a permanent basis has fully mitigated the transformer constrraint. However the substation still has only one incoming transfmission circuit.
20	NPL	11	23	N-1	4	48%	23	48%	No constraint within +5 years	
21	Pukenui	2	-	N-0	2	-	-	-	Transformer	Transfer capacity includes onsite diesel generation. Mobile transformer available.
22	Kaikohe 110kV	48	55	N-1	-	87%	55	44%	No constraint within +5 years	The Ngawha power station also supports the 110kV load but this is not available if both incoming 110kV circuits from Maungatapere are out of service. Approximately 24 MVA of the Kaikohe 110kV peak load will be transferred to Wiroa when the 110/33kV Wiroa substation is commissioned in FYE2024.
23	Kaitaia 110kV	24	-	N-0	19	-	-	-	Subtransmission circuit	Transfer capacity is diesel generation in northern area
24	[Zone Substation_16]					-			[Select one]	
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
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*

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11		*Consumer types defined by EDB**						
12		Residential	470	490	510	530	550	570
13		Other	80	85	90	95	100	105
14		[EDB consumer type]						
15		[EDB consumer type]						
16		[EDB consumer type]						
17		**Connections total**	550	575	600	625	650	675
18		**include additional rows if needed*						
19		**Distributed generation**						
20		Number of connections	210	220	230	240	250	260
21		Capacity of distributed generation installed in year (MVA)	1	24	33	17	1	33
22		**12c(ii) System Demand**						
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** — for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
25		GXP demand	20	21	22	23	24	-
26	*plus*	Distributed generation output at HV and above	57	57	57	57	57	82
27		**Maximum coincident system demand**	77	78	79	80	81	82
28	*less*	Net transfers to (from) other EDBs at HV and above	77	78	79	80	81	82
29		**Demand on system for supply to consumers' connection points**	-	-	-	-	-	-
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	22	23	25	28	30	-
32	*less*	Electricity exports to GXPs	101	94	155	240	280	590
33	*plus*	Electricity supplied from distributed generation	446	446	509	596	641	990
34	*less*	Net electricity supplied to (from) other EDBs						
35		**Electricity entering system for supply to ICPs**	367	375	379	384	391	400
36	*less*	Total energy delivered to ICPs	337	340	344	349	355	362
37		**Losses**	30	35	35	35	36	38
38								
39		**Load factor**	-	-	-	-	-	-
40		**Loss ratio**	8.2%	9.3%	9.2%	9.1%	9.2%	9.5%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**
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
8							
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	85.0	125.0	125.0	125.0	125.0	125.0
12	Class C (unplanned interruptions on the network)	745.6	266.0	257.0	249.0	241.0	241.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.00	1.00	1.00	1.00	1.00	1.00
15	Class C (unplanned interruptions on the network)	4.53	2.98	2.91	2.86	2.81	2.81

Company Name Top Energy

For Year Ended 31 March 2023

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

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

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

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Our constant price forecast is based on FYE 2023 prices. We have assumed an inflation rate of 15% for material and 6% for labour in FYE 2023. In subsequent years we have assumed an inflation rate of 2%, which is the mid-point of the Reserve Bank's target inflation range. Industry specific analysis of potential price movements is not considered justified given the forecast uncertainty.

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

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our constant price forecast is based on FYE 2023 prices. We have assumed an inflation rate of 15% for material and 6% for labour in FYE 2023. In subsequent years we have assumed an inflation rate of 2%, which is the mid-point of the Reserve Bank's target inflation range. Industry specific analysis of potential price movements is not considered justified given the forecast uncertainty.

Appendix B – Certification for Year Beginning Disclosures

TOP ENERGY®
Te Puna Hihiko

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Euan Richard Krogh, and David Alexander Sullivan, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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 Top Energy Ltd's corporate vision and strategy and are documented in retained records.

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Euan Richard Krogh

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David Alexander Sullivan

29 March 2022

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