# 2017 Asset Management Plan Update

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TOP ENERGY®
Te Puna Hihiko

# Introduction

It gives me great pleasure to present this Asset Management Plan Update to Top Energy's 2016 Network Asset Management Plan (AMP). Our 2017 AMP Update has been prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 and updates the regulatory schedules included in that AMP to cover the planning period commencing on 1 April 2017 and ending on 31 March 2027 (FYE2018-2027). It also documents material changes to the asset management strategies, levels of service, network development and lifecycle asset management plans described in our 2016 AMP. Hence it is not a stand-alone document and should be read in conjunction with our 2016 AMP.

The 2016 AMP, as updated by this 2017 AMP Update, remains the core asset management planning and operations document for our electricity transmission and distribution network and details planned inspection, maintenance and capital replacement strategies for the next ten years, as well as the targeted service level that we plan to deliver to our customers.

We continue to make good progress on implementing our network development plan and have invested approximately $16.0 million capital expenditure on our network assets during FYE2017. This investment has allowed us to:

- continue to secure land access rights over the route of our planned new 110kV line between Wiroa and Kaitaia. This is progressing well and we are on track to meeting our target of securing access rights over the complete route in FYE2019;
- commence the construction of a new zone substation in Omaunu Rd, Kaeo. This project, which should be completed in the second half of 2017, is expected to significantly improve the reliability of supply to consumers located in the coastal belt north of Waipapa;
- refurbish the Kawakawa substation including the addition of fans to increase the capacity of the supply transformers;
- add 110kV bus zone protection to the Kaikohe substation. The need for this became apparent after an incident in October 2015 when all our consumers lost supply for up to four hours due to the simultaneous tripping of Transpower's two incoming circuits from Maungatapere. While the cause of the tripping was never conclusively established, it is most unlikely that both circuits would have tripped had this bus zone protection been in place;
- install synchronising equipment on the generators at Taipa substation. This project will ensure that consumers supplied from this substation will not experience supply interruptions during planned outages of either the 110kV line or the single incoming 33kV circuit to the substation; and
- continue our line refurbishments with a particular focus on the 33kV Pukenui and Taipa lines. We have also replaced the insulators and crossarms on the 11kV China Clay feeder. This line is insulated to 33kV and will form the incoming supply to the new Kaeo substation;

In FY2018 we are introducing a programme to improve the storm resilience of the 11kV network and in time reducing the number of unplanned supply interruptions due to 11kV network faults by accelerating the rate at which we replace assets identified as defective during our routine asset inspections. This programme should eventually lead to reductions in our operational expenditure on service interruptions and emergencies.

Following the passage of the Health and Safety at Work Act 2015, we are taking a more conservative approach to the use of live line maintenance techniques and have discontinued the use of some more complex live line maintenance procedures. This will inevitably result in an increase in planned supply interruptions, although we have put strategies in place to minimise the impact of this on consumers. The extent that this will adversely impact our measured supply reliability is still unclear and the reliability targets set out in our 2016 AMP remain in place pending a comprehensive review of network reliability in FYE2018. Given the more conservative approach to the use of live line techniques, we expect to marginally exceed our reliability target in FYE2017, although this performance has been achieved only because we have been able to defer our planned shutdown of the 110kV Kaitaia line until FYE2018.

Our internal reliability targets, which we use to manage the network, reflect a significantly better level of reliability than the thresholds that the Commerce Commission uses to assess our compliance with its regulatory price-quality path, and we expect that this will continue to be the case even if the targets need to be revised.

For internal management purposes, including the setting of internal targets, we use a normalised measure of reliability that utilises the same normalisation methodology specified by the Commission for regulatory compliance purposes. We would prefer to use these normalised measures for forecasting reliability in the regulatory schedules included in our AMP. This is currently not permitted by the Commission, which requires the reliability forecasts in Schedule 12d to use measures that have not been normalised. We continue to emphasise to the Commission the need for alignment in the measurement of reliability that it uses for information disclosure with the measures that it uses for price-quality control. In our view, the normalised measures are more relevant to stakeholders as they more accurately reflect management performance and remove some of the volatility driven by unpredictable and variable weather conditions.

Also, following the passage of the Health and Safety at Work Act, we are taking a more cautious approach to the management of our fleet of wooden poles. This has resulted in a slight increase in the frequency of pole inspections and the use of an ultrasonic scanning technique to more accurately assess pole condition. We expect the number of wood pole replacements to increase because of these changes.

We continue to monitor the development of emerging technologies and their potential impact on our operation. We are particularly interested in developments in photovoltaics and battery technology and the potential for stand-alone household energy systems to meet the energy requirements of consumers living in areas that are uneconomic to supply using a grid connection. In order to gain first-hand experience in such applications, and the technical, commercial and legal implications if we were to get involved in providing such systems, we are planning to extend our current research on the operation of photovoltaic systems in parallel with the grid to the incorporation of photovoltaics in stand-alone off-grid supplies that could be provided to consumers in remote locations as an alternative to a grid connection. We are planning to trial such a system and are currently identifying an appropriate consumer willing to participate in such a trial. For this experiment, we envisage a hybrid system using both photovoltaics and bottled gas, and incorporating battery storage with a small gas-fuelled generator to provide supply security. We anticipate that this trial will provide information that will help us plan the continuing provision of an electricity supply in those parts of our supply area that are uneconomic to serve using traditional approaches.

We also acknowledge that very little new transmission capacity is currently being constructed in New Zealand due to subdued demand growth and uncertainty over the long-term impact of emerging technologies. It is possible that technologies such as battery storage could in time be more cost effective than a new transmission line in providing security of supply. We noted in our 2016 AMP that we had considered installation of diesel generation in the Kaitaia area as a lower cost alternative to constructing the new 110kV Wiroa-Kaitaia line, but that we had rejected this approach because of its functional limitations. Nevertheless, we have kept this option open by including provision for diesel or bio-diesel generation in our application to the Electricity Authority for clearance to construct our planned new geothermal generation units at Ngawha, as diesel generation could be an interim solution to improving supply security in our northern area until the potential of these emerging technologies is clearer. In the meantime, we are continuing to secure the route for the new line and provision for its construction remains in our capital expenditure forecast. We will not make a final decision as to how to proceed until the full line route has been secured and there has been an appropriate level of consultation with our consumers and other stakeholders.

We hope that you find this Asset Management Plan Update a succinct summary of the material changes to our 2016 AMP. We welcome your feedback on the update or 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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# 1. Asset Management Strategy and Delivery

We strive to continually improve the manner that we operate so as to achieve our strategic business objective, while at the same time complying with all relevant legislation and providing a safe working environment for our staff. Consistent with this strategy of continuous improvement, the following material changes were made during FYE 2017 to the way in which we manage our network assets.

## 1.1 Live Line Maintenance

Following the introduction of the Health and Safety at Work Act 2015, the electricity supply industry in New Zealand is reviewing its approach to live line construction and maintenance to ensure that industry practices are consistent with the Act's objective. The purpose of the Act is to provide for a balanced framework to secure the health and safety of workers and workplaces by protecting workers and other persons against harm to their health, safety and welfare by minimising risks arising from work to the extent that is reasonably practicable. Worksafe New Zealand interprets this requirement to mean that we should deenergise live conductors before working on or near them unless there is a good reason not to do so.

A policy of always deenergising conductors before working on our network assets would have a significant impact on the reliability of the supply that we provide our consumers. Consumers in our northern area would experience a significantly higher number of supply outages as an outage would be needed every time maintenance work was undertaken on our 110kV transmission line. Consumers supplied from long radial distribution feeders would also experience a significant impact. Our view, and that of most in the industry, is that disconnection in all situations is unnecessary as safe working practices for live line construction and maintenance are well developed and industry experience is that live line work can be undertaken safely if the correct procedures are diligently followed.

Nevertheless, we need to be cognisant of the risks of live line maintenance work and adapt our working practices to be more consistent with the purpose of the Act. As an interim response to the new legislation, we have developed significantly more conservative risk management procedures for the management of live line work. Under our new procedures:

- We have reduced the number of crews authorised to undertake live line work from three to one. This ensures that only specially trained and well experienced line mechanics undertake this work and that these workers get regular opportunities to practice and update their skills.
- A risk management procedure is in place that will determine whether a live line procedure is justified. This procedure considers:
    - the availability and practicality of an alternative methodology that will reduce either the consumer impact or the risk exposure. Such methodologies could include the installation of a temporary line break or the use of generation to maintain supply to downstream consumers, so that the task can be completed with the work site deenergised;
    - the impact on consumers if the line is deenergised. If this is low, then live line work will not be approved;
    - the time required to complete the task – tasks that require workers to be exposed to risk for long periods will not be approved;
    - the availability and complexity of a standard work practice. Standard work practices have been developed for all tasks that are permitted to be undertaken live. We have reduced the number of approved standard work practices from 28 to 16 to eliminate the more complex tasks.

The outcomes of this change to our working practices are that:

- All live line work on the 110kV transmission system is contracted out to contractors approved by Transpower to undertake similar work on its transmission system. A number of more complex asset replacements are no longer undertaken live but, when required, are scheduled to be undertaken during the next planned transmission outage. It is possible that some transmission system interruptions may need to be planned at short notice if an urgent replacement is required that cannot be undertaken live or deferred to the next scheduled interruption.

- The following procedures will no longer be undertaken live:
    - air break switch maintenance and installation;
    - termination and shackle pole and crossarm changes;
    - pole changes on significant angles: and
    - fitting lightning arresters.

These changes will adversely impact our reliability of supply in that the number of planned supply interruptions will increase. This is discussed further in Section 2.

## 1.2 Asset Management Maturity Assessment

There are no material changes to the Asset Management Maturity Assessment (AMMAT) presented in Schedule 13 of our 2016 AMP. We have therefore not included a revised schedule in this AMP Update.

# 2 Levels of Service

For internal management purposes, we measure and report supply reliability using normalised SAIDI and SAIFI measures, which are lower than the actual reliability experienced by our consumers. We use the same normalisation methodology as that used by the Commerce Commission when assessing regulatory compliance with our price-quality path; this is specified in the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2015 (Determination). Our internal reliability targets are more challenging than the limits set out in Schedule 4A of the Determination, because the Commission's limits are based on a requirement to maintain historic levels of reliability, whereas our asset management objective is to improve the reliability of the supply that we provide to our consumers.

Normalisation has two effects:

- It limits the impact of planned interruptions, since the normalised measure includes only 50% of the actual SAIDI and SAIFI impact of such interruptions; and
- The maximum unplanned SAIDI and SAIFI measure in any single calendar day is limited to the boundary value specified in Schedule 4A of the Determination, which limits the impact of major event days on the normalised measure. Major event days are days when there are widespread outages across the network, which is generally a consequence of extreme storm conditions. On such days our normal fault response capacity is exceeded. As we expect to experience, on average, only two major event days per year it would not be economic for us to develop a response capacity that would allow us to more effectively respond to such events.

We believe that reporting reliability against a normalised, rather than actual, measure is more meaningful to our stakeholders. The normalised measure is most sensitive to unplanned interruptions but is not distorted by the impact of extreme weather events. It is less sensitive to planned interruptions, which are less disruptive to consumers because they receive advance notice of the interruption. While normalised reliability is, in our view, an appropriate measure of management performance we are nevertheless endeavouring to improve the storm resilience of our network by accelerating the rate at which we rectify defects identified during routine inspections of our 11kV assets. This is the purpose of a new asset replacement programme being introduced in FYE2018.

Our revised approach to live line maintenance, as described in Section 1.1, and the acceleration of the rate at which we replace defective assets, will result in more planned interruptions. The effect this will have on our normalised reliability is not clear. As discussed in Section 3.2, we have put strategies in place to mitigate this impact, and in FYE2017 we expect to marginally exceed our reliability targets, although this achievement has only been possible by deferring the planned 110kV line shutdown to early FYE2018.

Our normalised SAIDI and SAIFI targets for FYE2018 will therefore remain at 345 minutes and 4.5 respectively, as signalled in in our 2016 AMP. However, for internal reporting purposes going forward, we are planning to separately categorise planned and unplanned interruptions, and also to disaggregate interruptions by voltage. This information will be used as the basis for reviewing our reliability targets for FYE2019 and beyond, and any revised targets will be disclosed in our 2018 AMP.

Our actual and targeted reliability, after normalisation using the Commission's methodology, is shown in Figures 2.1 and 2.2 below. The graphs are indicative only as the historical performance is not directly comparable to the performance targets going forward. Firstly, performance prior to FYE2008 was estimated rather than directly measured. Secondly the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commerce Commission's measurement methodology and, finally, the normalisation methodology was changed by the Commission for the current price-quality path regulatory period, which began in FYE2016.

**Figure 2.1: Actual and Targeted SAIDI**

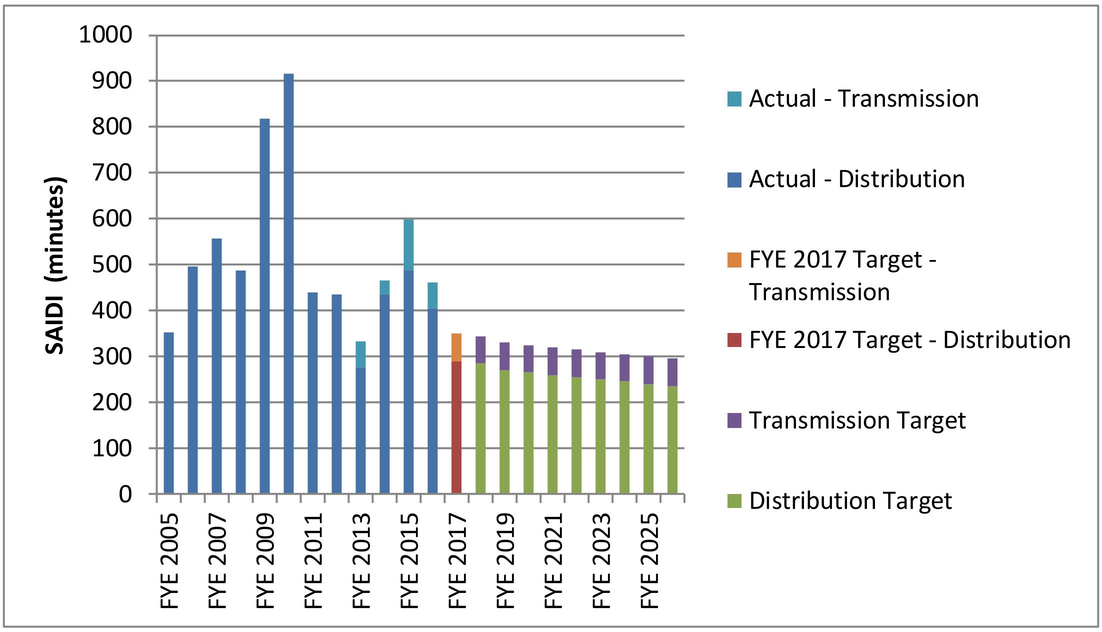
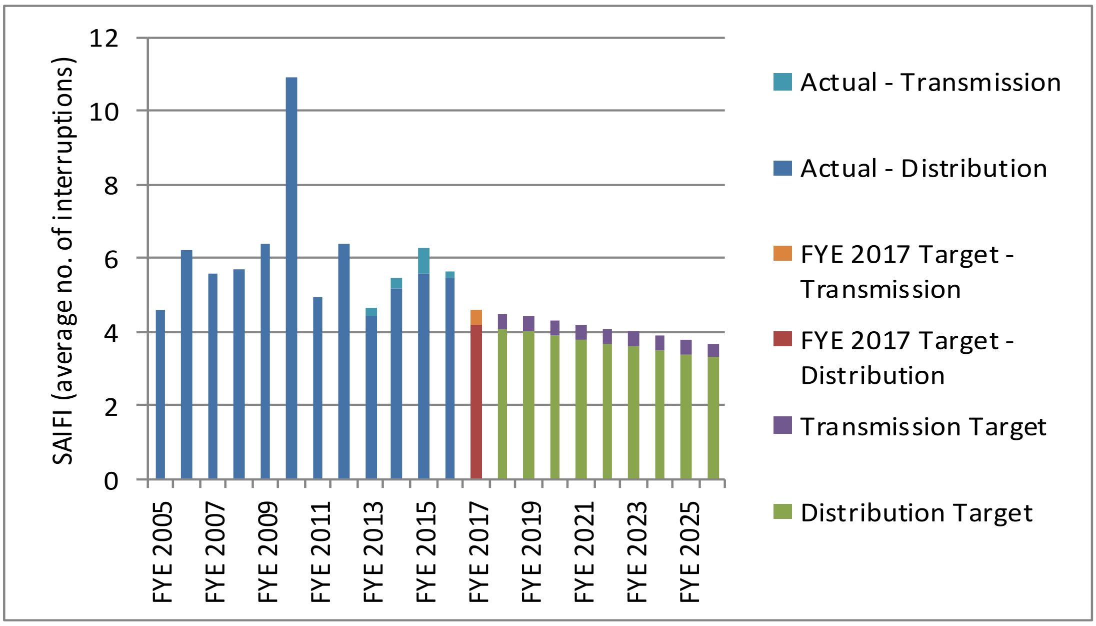



**Figure 2.2: Actual and Targeted SAIFI**




In accordance with the Commission's requirements, the forecast reliability in Schedule 12d has not been normalised. We believe forecasts of normalised reliability are a more useful measure for stakeholders as much of the volatility generated by unpredictable weather patterns is removed. We therefore continue to emphasise to the Commission that the measures it requires for forecasting reliability for information disclosure purposes must be aligned with the measures it uses for assessing price-quality path compliance, this being essential for meaningful comparison between past and future performance by our stakeholders.

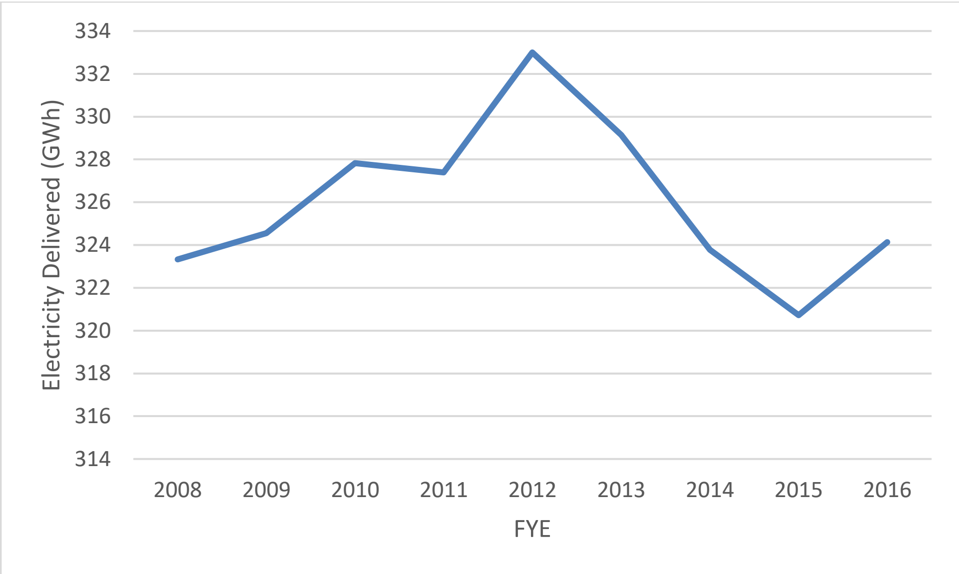
# 3 Network Development

## 3.1 New and Emerging Technologies

We continue to monitor the implementation of new technologies and their potential impact on our network development plans. While these impacts remain highly uncertain, a number of trends are becoming apparent. In particular:

- Notwithstanding an increase in the number of connections, electricity sales have progressively declined since 2012, and are currently at a similar level to 2008. We attribute this to the installation of more efficient electrical fittings and appliances (such as LED lighting), an increasing awareness within the community on the need for energy efficiency and the connection of rooftop photovoltaic generation. This is reflected in Figure 3.1, which shows our disclosed energy sales over the eight-year period 2008-16. Network demand has also remained static at round 70MW since FYE2011.

**Figure 3.1: Electricity Delivered to Consumers (GWh)**




We see this trend continuing, and even accelerating, through the medium term and only likely to be reversed when the penetration of plug-in electric vehicles becomes significant. This static or declining demand for electricity has a number of implications for the way we plan our network.

- Our planning strategy must not be based on the traditional premise that the demand for electricity will continually increase and needs to focus on improving supply reliability rather than on relieving capacity constraints. Given that our network development plan, including the planned new substation at Kaeo, is targeted primarily at reliability improvement, this does not indicate a significant change to our existing strategy.

- Nevertheless, over the planning period there could be localised areas where demand increases due to industry or commercial development, or changing land use. Given the highly uncertain impacts of emerging technologies, we need to manage these situations through the application of short-term, low cost interventions that will suffice until the long-term impact of the technological change becomes clearer. If we plan with a longer-term focus, there is a high risk of building assets that will eventually be stranded, at a high cost to all our consumers. Our solutions to developing network constraints are increasingly likely to be non-network interventions and, paradoxically given the current trend towards increased use of renewable energy, could involve the installation of diesel generation.

- There has been much discussion about the potential for systems using photovoltaic technology to be developed that will allow households to be become energy self-sufficient and consequently to disconnect from the grid. We think the likelihood of large numbers of such disconnections is small as systems capable of providing all a modern household’s energy requirements are unlikely to be economic in the medium term. Nevertheless, there is a potential for such systems to cost effectively supply consumers in remote locations that are currently uneconomic to serve. This could be through the installation of either standalone household systems or larger systems supplying small mini-grids isolated from our main network.

As described in Section 5.9.1 of our 2016 AMP, we are currently researching the impact of photovoltaic cells and batteries operated in parallel with our network. In FYE2018, we propose to extend this trial to an off-grid situation, where we will provide a stand-alone household energy supply to a consumer supplied from a relatively long dedicated high voltage spur line. The system we envisage for the trial is likely to be hybrid, using photovoltaics and bottled LPG as energy sources and to incorporate a battery, as well as a small gas fueled generator as a backup electricity source. We are currently in the process of identifying a suitable consumer to participate in the trial.

We expect this trial to provide valuable data on the costs and implications of operating and maintaining standalone systems in our supply area. It will also identify commercial and legal issues that will need to be addressed if we are to use standalone systems to meet our obligation to supply. We anticipate that this trial will provide information that will help us plan the continuing provision of an electricity supply in those parts of our supply area that are uneconomic to serve in a manner that cost effectively meets the expectations of all our stakeholders over the longer term.

## 3.2 Network Development Plan

### 3.2.1 Work Undertaken in FYE2017

A summary of the progress made on the major network development projects in FYE2017 is shown below.

- The acquisition of property rights for the 110kV Wiroa-Kaitaia line is progressing well and we expect to meet the target of FYE2019 for securing property rights over the full line route;
- Installation of bus zone protection at Kaikohe 110kV substation has commenced and is expected to be completed by year end;
- The rebuild of the Kawakawa substation, including the addition of fans to increase the capacity of the power transformers, is also expected to be completed by year end;
- Construction of the Kaeo substation commenced in January and is expected to be completed before the end of 2017. The transformers have been ordered and are due for delivery at the end of June;
- Reconfiguration of the 11kV network to allow supply from the new Kaeo substation has continued;
- Synchronisers have been installed on the Taipa generators, so that consumers supplied from the Taipa substation will not experience any supply interruptions during planned 110kV shutdowns and planned shutdowns of the 33kV line supplying the substation. Without synchronisers, these consumers experience short supply interruptions at the beginning and end of the shutdown.

  This project was not included in the 2016 AMP but was driven by the change in policy on live line work, as discussed in Section 1.1. A consequence of our revised approach to live line maintenance is that more shutdowns are required to complete the refurbishment work on the 33kV line supplying Taipa, and synchronisers on the Taipa generator allow this line to be shut down without interrupting supply to consumers.
- Refurbishment of the 33kV lines supplying Pukenui and Taipa has continued. Crossarms and insulators have also been replaced on the 11kV China Clay feeder. This line is constructed at 33kV and will be used to supply the Kaeo substation.

The planned shutdown of the Kaitaia 110kV transmission line scheduled for November 2016 has been deferred to November 2017, as no urgent repairs were required. This would indicate that the condition of this asset is improving as a result of the refurbishment work we have undertaken since the line was acquired from Transpower.

Our total capital expenditure on network assets in FYE2017 is expected to be approximately$16.0 million compared to a 2016 AMP budget forecast of $14.0 million.

### 3.2.2 Changes to FYE2018-27 Development Plan

There are no material changes to the network development plan going forward, with the major subtransmission projects still programmed for delivery generally in accordance with the timeline set out in the 2016 AMP. However, the change in policy on live line working led to minor changes in the detail of the plan and the way in which some asset replacement capital expenditure is planned. In particular:

- We are now planning to install generation at Omanaia to allow planned outages of the single 33kV incoming circuit for refurbishment work without interrupting supply to consumers.
- Asset replacements to address defects identified during asset inspections are now programmed where possible to be undertaken when a line is out of service for other reasons. As a result, many replacements will now occur earlier and we have provided for an additional $1 million per annum asset replacement capital expenditure to achieve this. Over time, this should lead to an improvement in the storm resilience of our network and a reduction in the number of unplanned interruptions. This should eventually lead to a reduction in our operational expenditure on service interruptions and emergencies.

Over the planning period it is anticipated that capital expenditure on network assets will average $16.5 million per year, with some variation about this average year on year. This includes an additional provision of $0.5 million per annum to provide for acceleration of the replacement of wood poles and the additional $1 million per annum for the remediation of other defects.

### 3.2.3 Ngawha Geothermal Power Station

The Top Energy Group has been granted resource consent for the installation of two new 25MW (net) geothermal power generating units at Ngawha to augment the 25MW (net) of generation capacity already installed. While no final decisions have been made, it is likely that the first of these units will be commissioned during FYE2021. To make this possible, we have applied to the Electricity Authority for an exemption under Section 90 of the Electricity Industry Act 2010 (the Act), from certain provisions of Part 3 of the Act, which limit the amount of generation and electricity distribution that can be owned and operated.

Planning for the connection of this unit to the national grid or our own network is at an early stage, to the extent that the connection voltage is still uncertain. Nevertheless, it is probable that the cost of any new lines will be fully funded from the project budget so that there will be no impact on our network capital expenditure forecast. We have therefore not made any provision for the connection of this new generating unit in our network development plan or network capital expenditure forecast.

### 3.2.4 Wiroa-Kaitaia Transmission Line

Due to the subdued load growth being experienced in most parts of the country and the uncertain impact of new and emerging technologies on the future demand for electricity supplied from the grid, very little new transmission capacity is currently being constructed in New Zealand. Notwithstanding this, we are proceeding with the acquisition of the property rights that we need before construction of the planned Wiroa-Kaitaia 110kV transmission line can begin.

We noted in our 2016 AMP that the installation of diesel generation was an alternative to the construction of this line and the exemption application to the Electricity Authority discussed in Section 3.2.3 includes provision for this alternative. We consider this prudent, as it could avoid the need for a second application should it become clear that the potential impact of new and emerging technologies is such that committing to the high capital cost of a second line would not be in the best interest of our consumers.

That said, no decision has been made and our network development plan still assumes that we will proceed with the construction of the new line. The installation of diesel generation for network support would be less costly and could be installed more quickly than a new line, so could form an interim solution to security of supply to Kaitaia until it is known whether new technologies will emerge that would make a new line redundant. However, diesel generation has a number of disadvantages. In particular:

- Diesel generation would avoid supply being interrupted during planned maintenance outages of the existing 110kV line, but would provide only limited protection against unplanned interruptions. Following such events, supply would be interrupted until the diesel generation could be started and put on load;

- Diesel generation would not support economic development of the northern region in that it would not provide additional secure supply capacity that could be utilised by industrial or commercial development that would provide employment and economic support to one of the most deprived areas of the country. If such development required a secure power supply, it would likely need to fund additional generation capacity to be used when a grid supply was not available.

- It would not reduce electricity losses in a network where losses are currently higher than any other distribution network in the country.

- Notwithstanding the fact that network support generation would only be operated for less than 45 hours per year, installation of more thermal generation at a time when government policy is to encourage investment in renewable generation and when there is a worldwide focus on reducing carbon emissions is a contrary step, and any thermal generation solution is likely to need to include a more sustainable fuel mix, such as bio diesel.

Our planned new transmission line would address all these issues, albeit at a higher capital cost than a diesel generation solution. Given the current high level of uncertainty in the future requirement for electric power transmission, the best way forward is far from clear, and may require an interim solution that has a lower capital cost than the new line. We will therefore not make a final decision until we are ready to commence construction of the new line and there has been an appropriate level of consultation with consumers and other stakeholders as to the path we should take.

# 4 Lifecycle Asset Management

The passage of the Health and Safety at Work Act 2015, and the experience of other EDBs in New Zealand and Australia has highlighted the risks posed by our aging wood pole fleet. We noted in Section 3.4.17 of our 2016 AMP that the average age of our distribution and low voltage wooden poles was 40 and 41 years respectively, while the expected average life of these assets is 45 years. Given the age of these assets and the potential consequences of a pole failure, we have increased the frequency of inspection of these assets and introduced ultrasonic scanning to obtain a more accurate assessment of pole condition.

We expect this change to increase the rate of wood pole replacement. As noted in Section 3.2.2 our capital expenditure forecast includes an additional $0.5 million per annum over the planning period to fund this additional work. Our operational expenditure forecast has also been adjusted to provide for the increased inspection cost.

As also noted in Section 3.2.2, we have accelerated the rate at which we rectify defects identified during routine asset inspections to increase the storm resilience of our network, reduce the number of unplanned interruptions and improve the productivity of our maintenance effort.

# 5 Appendices

## 5.1 Asset Management Plan Schedules

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| 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 Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| 9 | | **11a(i): Expenditure on Assets Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | | Consumer connection | 1,471 | 1,486 | 1,497 | 1,524 | 1,555 | 1,586 | 1,617 | 1,650 | 1,683 | 1,716 | 1,751 |
| 11 | | System growth | 4,754 | 4,694 | 2,032 | 4,258 | 1,332 | 1,637 | 6,276 | 2,943 | 3,250 | - | 1,304 |
| 12 | | Asset replacement and renewal | 5,964 | 7,278 | 9,261 | 9,817 | 6,490 | 8,206 | 6,493 | 9,337 | 7,140 | 10,154 | 8,149 |
| 13 | | Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| 14 | | Reliability, safety and environment: | | | | | | | | | | | |
| 15 | | Quality of supply | 4,497 | 3,883 | 4,406 | 5,113 | 6,663 | 5,775 | 4,689 | 3,781 | 7,889 | 8,294 | 8,198 |
| 16 | | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| 17 | | Other reliability, safety and environment | - | - | - | - | - | - | - | - | - | - | - |
| 18 | | **Total reliability, safety and environment** | 4,497 | 3,883 | 4,406 | 5,113 | 6,663 | 5,775 | 4,689 | 3,781 | 7,889 | 8,294 | 8,198 |
| 19 | | **Expenditure on network assets** | 16,686 | 17,341 | 17,196 | 20,712 | 16,040 | 17,203 | 19,075 | 17,710 | 19,962 | 20,164 | 19,402 |
| 20 | | Expenditure on non-network assets | 255 | 1,003 | 1,938 | 416 | 424 | 433 | 386 | 394 | 402 | 410 | 418 |
| 21 | | **Expenditure on assets** | 16,941 | 18,344 | 19,134 | 21,128 | 16,465 | 17,636 | 19,462 | 18,104 | 20,364 | 20,574 | 19,821 |
| 22 | | | | | | | | | | | | | |
| 23 | *plus* | Cost of financing | 355 | 202 | 196 | 391 | 250 | 812 | 1,362 | 194 | 630 | 1,092 | 305 |
| 24 | *less* | Value of capital contributions | 1,045 | 1,052 | 1,070 | 1,082 | 1,104 | 1,126 | 1,148 | 1,171 | 1,195 | 1,219 | 1,243 |
| 25 | *plus* | Value of vested assets | 26 | 27 | 55 | 56 | 56 | 86 | 87 | 89 | 120 | 120 | 120 |
| 26 | | | | | | | | | | | | | |
| 27 | | **Capital expenditure forecast** | 16,277 | 17,521 | 18,315 | 20,494 | 15,667 | 17,408 | 19,762 | 17,216 | 19,919 | 20,568 | 19,003 |
| 28 | | | | | | | | | | | | | |
| 29 | | Assets commissioned | 14,864 | 18,721 | 16,372 | 17,971 | 10,455 | 11,795 | 31,769 | 13,226 | 12,763 | 30,595 | 18,513 |

| *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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| 32 | | **$000 (in constant prices)** | | | | | | | | | | |
| 33 | Consumer connection | 1,471 | 1,486 | 1,468 | 1,465 | 1,465 | 1,465 | 1,465 | 1,465 | 1,465 | 1,465 | 1,465 |
| 34 | System growth | 4,754 | 4,694 | 1,992 | 4,093 | 1,255 | 1,512 | 5,684 | 2,613 | 2,829 | | 1,091 |
| 35 | Asset replacement and renewal | 5,964 | 7,278 | 9,079 | 9,436 | 6,116 | 7,581 | 5,881 | 8,291 | 6,216 | 8,666 | 6,819 |
| 36 | Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| 37 | Reliability, safety and environment: | | | | | | | | | | | |
| 38 | Quality of supply | 4,497 | 3,883 | 4,320 | 4,914 | 6,279 | 5,335 | 4,247 | 3,357 | 6,868 | 7,079 | 6,860 |
| 39 | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| 40 | Other reliability, safety and environment | - | - | - | - | - | - | - | - | - | - | - |
| 41 | **Total reliability, safety and environment** | 4,497 | 3,883 | 4,320 | 4,914 | 6,279 | 5,335 | 4,247 | 3,357 | 6,868 | 7,079 | 6,860 |
| 42 | **Expenditure on network assets** | 16,686 | 17,341 | 16,859 | 19,908 | 15,115 | 15,893 | 17,277 | 15,726 | 17,378 | 17,210 | 16,235 |
| 43 | Expenditure on non-network assets | 255 | 1,003 | 1,900 | 400 | 400 | 400 | 350 | 350 | 350 | 350 | 350 |
| 44 | **Expenditure on assets** | 16,941 | 18,344 | 18,759 | 20,308 | 15,515 | 16,293 | 17,627 | 16,076 | 17,728 | 17,560 | 16,585 |
| 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 | | 206 | 164 | | | | | | | | |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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* | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *50* | | | | | | | | | | | | |
| *51* | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| *52* | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| *53* | **Difference between nominal and constant price forecasts** | **$000** | | | | | | | | | | |
| *54* | Consumer connection | - | - | 29 | 59 | 90 | 121 | 152 | 185 | 218 | 251 | 286 |
| *55* | System growth | - | - | 40 | 165 | 77 | 125 | 592 | 330 | 421 | - | 213 |
| *56* | Asset replacement and renewal | - | - | 182 | 381 | 374 | 625 | 612 | 1,046 | 924 | 1,488 | 1,330 |
| *57* | Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| *58* | Reliability, safety and environment: | | | | | | | | | | | |
| *59* | Quality of supply | - | - | 86 | 199 | 384 | 440 | 442 | 424 | 1,021 | 1,215 | 1,338 |
| *60* | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| *61* | Other reliability, safety and environment | - | - | - | - | - | - | - | - | - | - | - |
| *62* | **Total reliability, safety and environment** | - | - | 86 | 199 | 384 | 440 | 442 | 424 | 1,021 | 1,215 | 1,338 |
| *63* | **Expenditure on network assets** | - | - | 337 | 804 | 925 | 1,310 | 1,798 | 1,984 | 2,584 | 2,954 | 3,167 |
| *64* | Expenditure on non-network assets | - | - | 38 | 16 | 24 | 33 | 36 | 44 | 52 | 60 | 68 |
| *65* | **Expenditure on assets** | - | - | 375 | 820 | 950 | 1,343 | 1,835 | 2,028 | 2,636 | 3,014 | 3,236 |
| *66* | | | | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| *67* | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| *68* | **11a(ii): Consumer Connection** | | | | | | |
| *69* | *Consumer types defined by EDB** | **$000 (in constant prices)** | | | | | |
| *70* | All types | 1,471 | 1,486 | 1,468 | 1,465 | 1,465 | 1,465 |
| *71* | | | | | | | |
| *72* | | | | | | | |
| *73* | | | | | | | |
| *74* | | | | | | | |
| *75* | **include additional rows if needed* | | | | | | |
| *76* | **Consumer connection expenditure** | 1,471 | 1,486 | 1,468 | 1,465 | 1,465 | 1,465 |
| *77* | *less* Capital contributions funding consumer connection | 1,045 | 1,052 | 1,049 | 1,040 | 1,040 | 1,040 |
| *78* | **Consumer connection less capital contributions** | 426 | 434 | 419 | 425 | 425 | 425 |
| | | | | | | | |
| *79* | **11a(iii): System Growth** | | | | | | |
| *80* | Subtransmission | 246 | 155 | 13 | | | |
| *81* | Zone substations | 2,659 | 3,263 | 882 | 3,517 | | |
| *82* | Distribution and LV lines | 1,834 | 867 | 1,097 | 576 | 1,255 | 1,512 |
| *83* | Distribution and LV cables | 15 | 204 | | | | |
| *84* | Distribution substations and transformers | | | | | | |
| *85* | Distribution switchgear | | 205 | | | | |
| *86* | Other network assets | | | | | | |
| *87* | **System growth expenditure** | 4,754 | 4,694 | 1,992 | 4,093 | 1,255 | 1,512 |
| *88* | *less* Capital contributions funding system growth | | | | | | |
| *89* | **System growth less capital contributions** | 4,754 | 4,694 | 1,992 | 4,093 | 1,255 | 1,512 |
| *90* | | | | | | | |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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* |
|---|---|---|---|---|---|---|---|---|
| 92 | | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 93 | **11a(iv): Asset Replacement and Renewal** | | **$000 (in constant prices)** | | | | | |
| 94 | Subtransmission | | 1,636 | 2,087 | 2,811 | 873 | 645 | 956 |
| 95 | Zone substations | | 1,214 | 97 | 1,306 | 3,592 | 428 | 1,260 |
| 96 | Distribution and LV lines | | 2,261 | 4,671 | 4,517 | 4,258 | 4,290 | 4,638 |
| 97 | Distribution and LV cables | | | | | 261 | 283 | 257 |
| 98 | Distribution substations and transformers | | 258 | | 186 | 186 | 186 | 186 |
| 99 | Distribution switchgear | | 595 | 423 | 259 | 266 | 284 | 284 |
| 100 | Other network assets | | | | | | | |
| 101 | **Asset replacement and renewal expenditure** | | 5,964 | 7,278 | 9,079 | 9,436 | 6,116 | 7,581 |
| 102 | *less* Capital contributions funding asset replacement and renewal | | | | | | | |
| 103 | **Asset replacement and renewal less capital contributions** | | 5,964 | 7,278 | 9,079 | 9,436 | 6,116 | 7,581 |
| 104 | | | | | | | | |

| sch ref | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
|---|---|---|---|---|---|---|---|---|
| 106 | | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 107 | **11a(v):Asset Relocations** | | | | | | | |
| 108 | *Project or programme** | | **$000 (in constant prices)** | | | | | |
| 109 | | | | | | | | |
| 110 | | | | | | | | |
| 111 | | | | | | | | |
| 112 | | | | | | | | |
| 113 | | | | | | | | |
| 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 122 | **11a(vi):Quality of Supply** | | | | | | | |
| 123 | *Project or programme** | | **$000 (in constant prices)** | | | | | |
| 124 | Wiroa-Kaitaia 110kV line - property rights | | 1,924 | 2,195 | 774 | | | |
| 125 | Wiroa-Kaitaia 110kV line - construction | | | | | 1,957 | 4,323 | 4,146 |
| 126 | Bus Zone Protection | | 826 | | 659 | | | |
| 127 | Diesel Generation | | 110 | 91 | | 998 | | |
| | Feeder Interconnections | | | 160 | 85 | 986 | 1,051 | 880 |
| | Protection Upgrades | | 729 | 363 | 86 | 117 | 112 | |
| | Russell Reinforcement | | | | 1,100 | | | |
| 128 | SCADA and Control | | 106 | 171 | 994 | 256 | 398 | |
| 129 | **include additional rows if needed* | | | | | | | |
| 130 | All other projects or programmes - quality of supply | | 802 | 903 | 622 | 600 | 395 | 309 |
| 131 | **Quality of supply expenditure** | | 4,497 | 3,883 | 4,320 | 4,914 | 6,279 | 5,335 |
| 132 | *less* Capital contributions funding quality of supply | | | | | | | |
| 133 | **Quality of supply less capital contributions** | | 4,497 | 3,883 | 4,320 | 4,914 | 6,279 | 5,335 |
| 134 | | | | | | | | |

| | |
|---|---|
| Company Name | Top Energy Ltd |
| AMP Planning Period | 1 April 2017 – 31 March 2027 |

# 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 |
|---|---|---|---|---|---|---|---|---|
| 135 | | | | | | | | |
| 136 | | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 137 | **11a(vii): Legislative and Regulatory** | | | | | | | |
| 138 | *Project or programme** | | **$000 (in constant prices)** | | | | | |
| 139 | | | | | | | | |
| 140 | | | | | | | | |
| 141 | | | | | | | | |
| 142 | | | | | | | | |
| 143 | | | | | | | | |
| 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 | | | | | | | | |

| sch ref | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|---|
| 150 | | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 151 | **11a(viii): Other Reliability, Safety and Environment** | | | | | | | |
| 152 | *Project or programme** | | **$000 (in constant prices)** | | | | | |
| 153 | | | | | | | | |
| 154 | | | | | | | | |
| 155 | | | | | | | | |
| 156 | | | | | | | | |
| 157 | | | | | | | | |
| 158 | **include additional rows if needed* | | | | | | | |
| 159 | All other projects or programmes - other reliability, safety and environment | | | | | | | |
| 160 | **Other reliability, safety and environment expenditure** | | - | - | - | - | - | - |
| 161 | *less* Capital contributions funding other reliability, safety and environment | | | | | | | |
| 162 | **Other reliability, safety and environment less capital contributions** | | - | - | - | - | - | - |
| 163 | | | | | | | | |

| sch ref | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|---|
| 164 | | | | | | | | |
| 165 | | for year ended | **31 Mar 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 166 | **11a(ix): Non-Network Assets** | | | | | | | |
| 167 | **Routine expenditure** | | | | | | | |
| 168 | *Project or programme** | | **$000 (in constant prices)** | | | | | |
| 169 | | | | | | | | |
| 170 | Software / systems | | | 528 | 1,500 | | | |
| 171 | | | | | | | | |
| 172 | | | | | | | | |
| 173 | | | | | | | | |
| 174 | **include additional rows if needed* | | | | | | | |
| 175 | All other projects or programmes - routine expenditure | | 255 | 475 | 400 | 400 | 400 | 400 |
| 176 | **Routine expenditure** | | 255 | 1,003 | 1,900 | 400 | 400 | 400 |
| 177 | **Atypical expenditure** | | | | | | | |
| 178 | *Project or programme** | | | | | | | |
| 179 | | | | | | | | |
| 180 | | | | | | | | |
| 181 | | | | | | | | |
| 182 | | | | | | | | |
| 183 | | | | | | | | |
| 184 | **include additional rows if needed* | | | | | | | |
| 185 | All other projects or programmes - atypical expenditure | | | | | | | |
| 186 | **Atypical expenditure** | | - | - | - | - | - | - |
| 187 | | | | | | | | |
| 188 | **Expenditure on non-network assets** | | 255 | 1,003 | 1,900 | 400 | 400 | 400 |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| 9 | **Operational Expenditure Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | Service interruptions and emergencies | 1,762 | 1,200 | 1,224 | 1,248 | 1,273 | 1,299 | 1,325 | 1,351 | 1,378 | 1,406 | 1,434 |
| 11 | Vegetation management | 1,790 | 1,730 | 1,767 | 1,804 | 1,842 | 1,881 | 1,921 | 1,962 | 2,003 | 2,046 | 2,089 |
| 12 | Routine and corrective maintenance and inspection | 2,013 | 2,122 | 2,088 | 2,130 | 2,268 | 2,315 | 2,321 | 2,417 | 2,366 | 2,418 | 2,579 |
| 13 | Asset replacement and renewal | 571 | 1,088 | 1,109 | 1,131 | 1,154 | 1,177 | 1,201 | 1,225 | 1,249 | 1,274 | 1,300 |
| 14 | **Network Opex** | 6,136 | 6,140 | 6,188 | 6,314 | 6,538 | 6,672 | 6,768 | 6,955 | 6,997 | 7,144 | 7,402 |
| 15 | System operations and network support | 4,135 | 4,915 | 5,013 | 5,114 | 5,216 | 5,320 | 5,427 | 5,535 | 5,646 | 5,759 | 5,874 |
| 16 | Business support | 3,878 | 4,446 | 4,637 | 4,730 | 4,930 | 5,029 | 5,130 | 5,232 | 5,337 | 5,444 | 5,552 |
| 17 | **Non-network opex** | 8,013 | 9,361 | 9,650 | 9,843 | 10,146 | 10,349 | 10,556 | 10,767 | 10,983 | 11,202 | 11,426 |
| 18 | **Operational expenditure** | 14,149 | 15,501 | 15,838 | 16,157 | 16,684 | 17,021 | 17,324 | 17,722 | 17,980 | 18,346 | 18,828 |

| 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| 21 | | **$000 (in constant prices)** | | | | | | | | | | |
| 22 | Service interruptions and emergencies | 1,762 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 |
| 23 | Vegetation management | 1,790 | 1,730 | 1,732 | 1,734 | 1,736 | 1,738 | 1,740 | 1,742 | 1,744 | 1,746 | 1,748 |
| 24 | Routine and corrective maintenance and inspection | 2,013 | 2,122 | 2,047 | 2,047 | 2,137 | 2,138 | 2,102 | 2,146 | 2,060 | 2,064 | 2,158 |
| 25 | Asset replacement and renewal | 571 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 | 1,088 |
| 26 | **Network Opex** | 6,136 | 6,140 | 6,067 | 6,069 | 6,161 | 6,164 | 6,130 | 6,176 | 6,091 | 6,097 | 6,193 |
| 27 | System operations and network support | 4,135 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 | 4,915 |
| 28 | Business support | 3,878 | 4,446 | 4,546 | 4,546 | 4,646 | 4,646 | 4,646 | 4,646 | 4,646 | 4,646 | 4,646 |
| 29 | **Non-network opex** | 8,013 | 9,361 | 9,461 | 9,461 | 9,561 | 9,561 | 9,561 | 9,561 | 9,561 | 9,561 | 9,561 |
| 30 | **Operational expenditure** | 14,149 | 15,501 | 15,528 | 15,530 | 15,722 | 15,725 | 15,691 | 15,737 | 15,652 | 15,658 | 15,754 |
| 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 | 251 | 227 | 229 | 232 | 234 | 236 | 239 | 241 | 243 | 246 | 248 |

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

| 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** |
| 41 | **Difference between nominal and real forecasts** | **$000** | | | | | | | | | | |
| 42 | Service interruptions and emergencies | - | - | 24 | 48 | 73 | 99 | 125 | 151 | 178 | 206 | 234 |
| 43 | Vegetation management | - | - | 35 | 70 | 106 | 143 | 181 | 220 | 259 | 300 | 341 |
| 44 | Routine and corrective maintenance and inspection | - | - | 41 | 83 | 131 | 176 | 219 | 271 | 306 | 354 | 421 |
| 45 | Asset replacement and renewal | - | - | 22 | 44 | 67 | 90 | 113 | 137 | 162 | 187 | 212 |
| 46 | **Network Opex** | - | - | 121 | 245 | 377 | 508 | 638 | 779 | 906 | 1,047 | 1,208 |
| 47 | System operations and network support | - | - | 98 | 199 | 301 | 405 | 512 | 620 | 731 | 844 | 959 |
| 48 | Business support | - | - | 91 | 184 | 284 | 383 | 484 | 586 | 691 | 798 | 906 |
| 49 | **Non-network opex** | - | - | 189 | 382 | 585 | 788 | 995 | 1,206 | 1,422 | 1,641 | 1,865 |
| 50 | **Operational expenditure** | - | - | 311 | 627 | 962 | 1,296 | 1,633 | 1,985 | 2,327 | 2,688 | 3,074 |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## SCHEDULE 12a: REPORT ON ASSET CONDITION

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

| *sch ref* | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | **Asset condition at start of planning period (percentage of units by grade)** | | | | | | |
| 8 | | | | | | | | | | | |
| 9 | **Voltage** | **Asset category** | **Asset class** | **Units** | **Grade 1** | **Grade 2** | **Grade 3** | **Grade 4** | **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. | 0.99% | 0.40% | 91.17% | 7.45% | - | 2 | 1.50% |
| 11 | All | Overhead Line | Wood poles | No. | 1.40% | 13.59% | 79.51% | 5.50% | - | 2 | 15.00% |
| 12 | All | Overhead Line | Other pole types | No. | - | - | - | 100.00% | - | 3 | - |
| 13 | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | - | - | 89.89% | 10.11% | - | 2 | - |
| 14 | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | - | - | 100.00% | - | - | 2 | - |
| 15 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | - | - | 2.72% | 97.28% | - | 2 | - |
| 16 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Oil pressurised) | km | NA | NA | NA | NA | NA | N/A | NA |
| 17 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Gas pressurised) | km | NA | NA | NA | NA | NA | N/A | NA |
| 18 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (PILC) | km | NA | NA | NA | NA | NA | N/A | NA |
| 19 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (XLPE) | km | NA | NA | NA | NA | NA | N/A | NA |
| 20 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Oil pressurised) | km | NA | NA | NA | NA | NA | N/A | NA |
| 21 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Gas Pressurised) | km | NA | NA | NA | NA | NA | N/A | NA |
| 22 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (PILC) | km | NA | NA | NA | NA | NA | N/A | NA |
| 23 | HV | Subtransmission Cable | Subtransmission submarine cable | km | NA | NA | NA | NA | NA | N/A | NA |
| 24 | HV | Zone substation Buildings | Zone substations up to 66kV | No. | - | - | 70.59% | 29.41% | - | 3 | - |
| 25 | HV | Zone substation Buildings | Zone substations 110kV+ | No. | - | - | 100.00% | - | - | 3 | - |
| 26 | HV | Zone substation switchgear | 22/33kV CB (Indoor) | No. | - | - | 5.56% | 94.44% | - | 3 | - |
| 27 | HV | Zone substation switchgear | 22/33kV CB (Outdoor) | No. | - | 5.26% | 19.30% | 75.44% | - | 3 | 5.00% |
| 28 | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | NA | NA | NA | NA | NA | N/A | NA |
| 29 | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | 8.46% | 24.62% | 36.15% | 30.77% | - | 3 | 33.00% |
| 30 | HV | Zone substation switchgear | 33kV RMU | No. | NA | NA | NA | NA | NA | N/A | NA |
| 31 | HV | Zone substation switchgear | 50/66/110kV CB (Indoor) | No. | NA | NA | NA | NA | NA | N/A | NA |
| 32 | HV | Zone substation switchgear | 50/66/110kV CB (Outdoor) | No. | - | 10.00% | 60.00% | 30.00% | - | 3 | 10.00% |
| 33 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (ground mounted) | No. | 13.11% | - | 68.85% | 18.03% | - | 3 | 15.00% |
| 34 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | - | - | 66.67% | 33.33% | - | 3 | 45.00% |
| 35 | | | | | NA | NA | NA | NA | NA | N/A | NA |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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** | **Grade 1** | **Grade 2** | **Grade 3** | **Grade 4** | **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. | - | 37.50% | 41.67% | 20.83% | - | 4 | - |
| *40* | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 2.63% | 1.85% | 91.10% | 4.42% | - | 2 | - |
| *41* | HV | Distribution Line | Distribution OH Aerial Cable Conductor | km | NA | NA | NA | NA | NA | N/A | NA |
| *42* | HV | Distribution Line | SWER conductor | km | 18.09% | 11.53% | 67.22% | 3.16% | - | 2 | - |
| *43* | HV | Distribution Cable | Distribution UG XLPE or PVC | km | - | - | 77.83% | 22.17% | - | 2 | - |
| *44* | HV | Distribution Cable | Distribution UG PILC | km | - | - | 96.12% | 3.88% | - | 2 | - |
| *45* | HV | Distribution Cable | Distribution Submarine Cable | km | - | - | 83.33% | 16.67% | - | 2 | - |
| *46* | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers | No. | 7.50% | 0.28% | 73.61% | 18.61% | - | 3 | 7.50% |
| *47* | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | NA | NA | NA | NA | NA | N/A | NA |
| *48* | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | 10.32% | 6.18% | 65.60% | 17.90% | - | 3 | - |
| *49* | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | NA | NA | NA | NA | NA | N/A | NA |
| *50* | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | - | 0.31% | 68.65% | 31.03% | - | 3 | 1.00% |
| *51* | HV | Distribution Transformer | Pole Mounted Transformer | No. | 8.19% | 3.00% | 73.98% | 14.82% | - | 3 | - |
| *52* | HV | Distribution Transformer | Ground Mounted Transformer | No. | 0.48% | 0.60% | 84.25% | 14.66% | - | 3 | - |
| *53* | HV | Distribution Transformer | Voltage regulators | No. | - | - | 55.56% | 44.44% | - | 3 | - |
| *54* | HV | Distribution Substations | Ground Mounted Substation Housing | No. | - | - | 100.00% | - | - | 3 | - |
| *55* | LV | LV Line | LV OH Conductor | km | 1.97% | 2.43% | 93.83% | 1.77% | - | 2 | - |
| *56* | LV | LV Cable | LV UG Cable | km | 1.33% | 5.38% | 89.57% | 3.72% | - | 2 | - |
| *57* | LV | LV Streetlighting | LV OH/UG Streetlight circuit | km | - | 0.26% | 98.10% | 1.65% | - | 2 | - |
| *58* | LV | Connections | OH/UG consumer service connections | No. | 2.76% | 5.08% | 78.02% | 14.13% | - | 2 | - |
| *59* | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | - | 12.56% | 17.94% | 69.51% | | 3 | - |
| *60* | All | SCADA and communications | SCADA and communications equipment operating as a single system | Lot | - | - | 100.00% | - | - | 3 | - |
| *61* | All | Capacitor Banks | Capacitors including controls | No. | - | 20.00% | 75.00% | 5.00% | - | 3 | - |
| *62* | All | Load Control | Centralised plant | Lot | - | - | 100.00% | - | - | 3 | - |
| *63* | All | Load Control | Relays | No. | NA | NA | NA | NA | NA | N/A | NA |
| *64* | All | Civils | Cable Tunnels | km | NA | NA | NA | NA | NA | N/A | NA |

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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 | 60% | 17 | 60% | No constraint within +5 years | |
| 10 | Kawakawa | 5 | 5 | N-1 | 3 | 99% | 7 | 84% | No constraint within +5 years | |
| 11 | Moerewa | 4 | 5 | N-1 | 2 | 82% | 5 | 200% | No constraint within +5 years | |
| 12 | Waipapa | 11 | 23 | N-1 | 6 | 46% | 23 | 27% | No constraint within +5 years | |
| 13 | Omanaia | 2 | - | N-0 | - | - | - | - | Transformer | Mobile transformer available. There is also a single incoming subtransmission circuit |
| 14 | Haruru | 6 | 23 | N-1 | 1 | 25% | 23 | 27% | No constraint within +5 years | |
| 15 | Mt Pokaka | 2 | - | N-0 | 1 | - | - | - | Transformer | Mobile transformer available. |
| 16 | Kerikeri | 7 | 23 | N-1 | 6 | 29% | 23 | 32% | No constraint within +5 years | |
| 17 | Kaeo | - | - | N-1 | | - | 9 | 61% | Subtransmission circuit | There will be only one incoming subtransmission circuit until the southern section of the 110kV line is completed, expected to be in FYE2022. |
| 18 | Okahu Rd | 9 | 12 | N-1 | 4 | 74% | 12 | 78% | No constraint within +5 years | |
| 19 | Taipa | 5 | | N-0 | 4 | - | - | - | Transformer | Transfer capacity is standby diesel generation installed at the substation site. There is also a single incoming subtransmission circuit |
| 20 | NPL | 12 | 23 | N-1 | 4 | 54% | 23 | 54% | No constraint within +5 years | |
| 21 | Pukenui | 2 | - | N-0 | - | - | - | - | Transformer | Mobile transformer available. There is also a single incoming subtransmission circuit |
| 22 | Kaikohe 110kV | 46 | 30 | N-1 | 25 | 154% | 30 | 164% | Transformer | Transfer capacity is Ngawha generation, which is connected to the 33kV subtransmission network and which is normally in operation. |
| 23 | Kaitaia 110kV | 26 | 25 | N-1 | 4 | 102% | 40 | 65% | Subtransmission circuit | Transfer capacity is Taipa generation. Firm capacity limited by single incoming 110kV circuit. |
| 24 | | | | | | - | | | | |
| 25 | | | | | | - | | | | |
| 26 | | | | | | - | | | | |
| 27 | | | | | | - | | | | |
| 28 | | | | | | - | | | | |

29 *[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

| | |
|---|---|
| *Company Name* | **Top Energy Ltd** |
| *AMP Planning Period* | **1 April 2017 – 31 March 2027** |

## 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 11 | *Consumer types defined by EDB** | | | | | | | |
| 12 | Residential | | 320 | 350 | 350 | 350 | 350 | 350 |
| 13 | Commercial | | 5 | 5 | 5 | 5 | 5 | 5 |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| 17 | **Connections total** | | 325 | 355 | 355 | 355 | 355 | 355 |
| 18 | **include additional rows if needed* | | | | | | | |
| 19 | **Distributed generation** | | | | | | | |
| 20 | Number of connections | | 140 | 150 | 165 | 182 | 200 | 220 |
| 21 | Capacity of distributed generation installed in year (MVA) | | 0.50 | 0.60 | 0.66 | 0.73 | 25.80 | 0.88 |
| 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| 25 | GXP demand | | 43 | 44 | 44 | 44 | 19 | 19 |
| 26 | *plus* Distributed generation output at HV and above | | 25 | 25 | 25 | 25 | 50 | 50 |
| 27 | **Maximum coincident system demand** | | 68 | 69 | 69 | 69 | 69 | 69 |
| 28 | *less* Net transfers to (from) other EDBs at HV and above | | | | | | | |
| 29 | **Demand on system for supply to consumers' connection points** | | 68 | 69 | 69 | 69 | 69 | 69 |
| 30 | **Electricity volumes carried (GWh)** | | | | | | | |
| 31 | Electricity supplied from GXPs | | 173 | 173 | 173 | 173 | 88 | 20 |
| 32 | *less* Electricity exports to GXPs | | 15 | 15 | 15 | 15 | 30 | 62 |
| 33 | *plus* Electricity supplied from distributed generation | | 200 | 200 | 200 | 200 | 300 | 400 |
| 34 | *less* Net electricity supplied to (from) other EDBs | | | | | | | |
| 35 | **Electricity entering system for supply to ICPs** | | 358 | 358 | 358 | 358 | 358 | 358 |
| 36 | *less* Total energy delivered to ICPs | | 325 | 325 | 325 | 325 | 325 | 325 |
| 37 | **Losses** | | 33 | 33 | 33 | 33 | 33 | 33 |
| 38 | | | | | | | | |
| 39 | **Load factor** | | 60% | 59% | 59% | 59% | 59% | 59% |
| 40 | **Loss ratio** | | 9.2% | 9.2% | 9.2% | 9.2% | 9.2% | 9.2% |

| | |
|---|---|
| Company Name | **Top Energy Ltd** |
| AMP Planning Period | **1 April 2017 – 31 March 2027** |
| 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 17** | **31 Mar 18** | **31 Mar 19** | **31 Mar 20** | **31 Mar 21** | **31 Mar 22** |
| *10* | **SAIDI** | | | | | | |
| *11* | Class B (planned interruptions on the network) | 41.3 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 |
| *12* | Class C (unplanned interruptions on the network) | 580.5 | 245.0 | 230.0 | 225.0 | 220.0 | 215.0 |
| *13* | **SAIFI** | | | | | | |
| *14* | Class B (planned interruptions on the network) | 0.28 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |
| *15* | Class C (unplanned interruptions on the network) | 5.36 | 3.75 | 3.65 | 3.55 | 3.45 | 3.40 |

| | |
|---|---|
| Company Name | Top Energy Ltd |
| For Year Ended | 31 March 2018 |

# Schedule 14a Mandatory Explanatory Notes on Forecast Information

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)*

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

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 disclosure year, as disclosed in Schedule 11a.

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

We have derived the nominal capital expenditure forecast by escalating the constant price forecast by 2% per annum after FYE2018. While this is higher than the current inflation rate, it is appropriate for a long term forecast as it is the mid-point of the Reserve Bank's 1-3% inflation target. In our view, there is little point in deriving a more accurate estimate of inflationary cost increases, given the high level of uncertainty in the other paramaters and assumptions on which our forecast is based.

*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 disclosure year, as disclosed in Schedule 11b.

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

We have derived the nominal operational expenditure forecast by escalating the constant price forecast by 2% per annum after FYE2018. While this is higher than the current inflation rate, it is appropriate for a long term forecast as it is the mid-point of the Reserve Bank's 1-3% inflation target. In our view, there is little point in deriving a more accurate estimate of inflationary cost increases, given the high level of uncertainty in the other paramaters and assumptions on which our forecast is based.

## 5.2 Appendix E – 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, Murray Ian Bain and Gregory Mark Steed, 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.

•

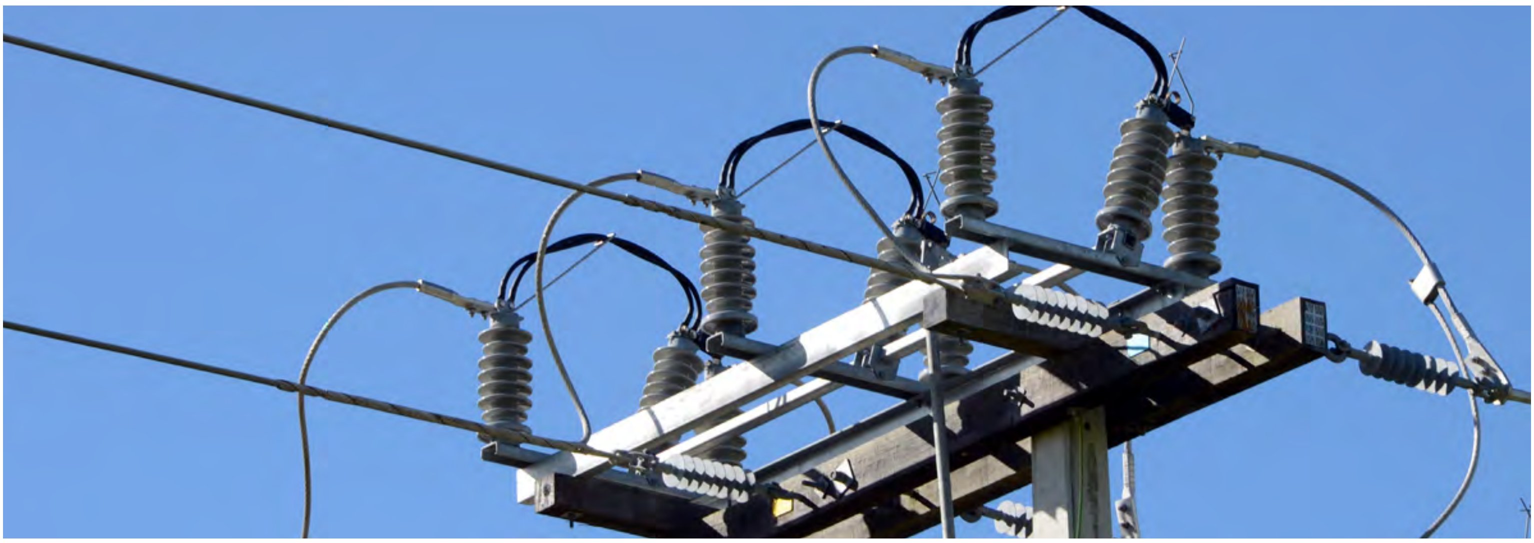
b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

M I Bain

G M Steed

28 March 2017

***Top Energy Limited***
***Level 2, John Butler Centre***
***60 Kerikeri Road***
***Kerikeri***
***PO Box 43 Kerikeri 0245***
***New Zealand***



***www.topenergy.co.nz***