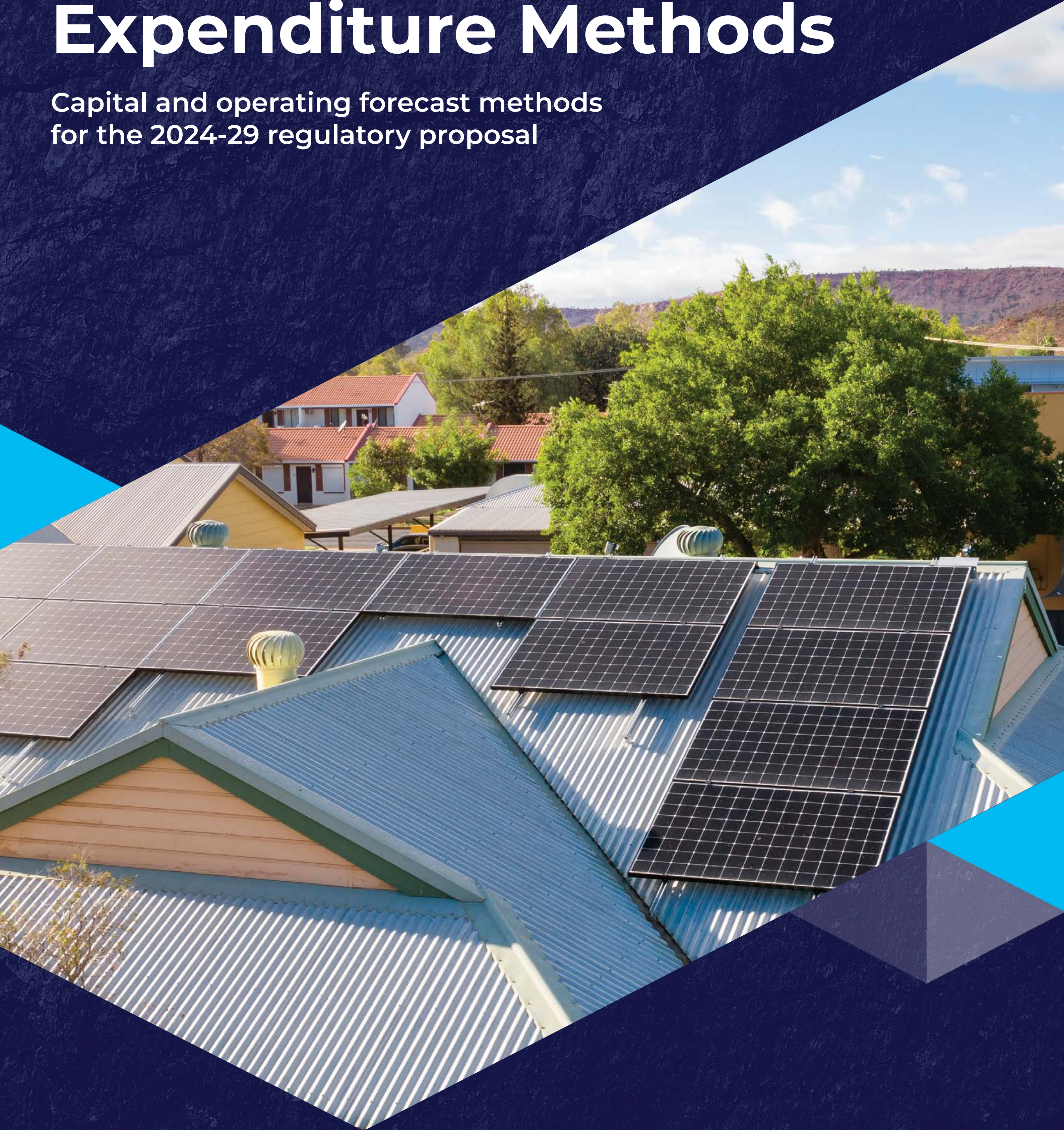
PowerWater

Forecast Expenditure Methods

Capital and operating forecast methods for the 2024-29 regulatory proposal



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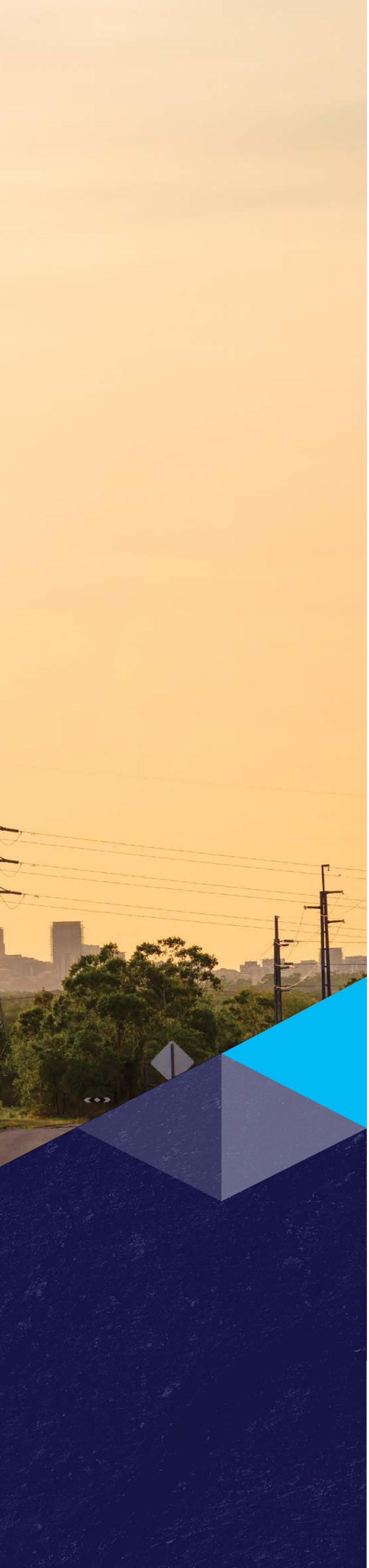

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Context

In January 2023, we will be submitting a regulatory proposal to the Australian Energy Regulator. The proposal will identify expenditure plans for our regulated electricity network for the 2024-29 period. This document provides an opportunity to start a conversation with our stakeholders on our methods to forecast expenditure. We have been making significant improvements in response to stakeholder feedback in our last determination. Key changes include a strategic focus on transformational changes in the energy sector, deep engagement with stakeholders and evolving to 'best practice' methods used by other networks.

Power and Water Corporation (Power and Water) is the essential service provider in the Northern Territory (NT) providing electricity, gas, water and sewerage services to households and businesses.

Our purpose is to make a difference to the lives of Territorians.

Our electricity services provide power to 90 communities in the NT over a vast landmass of 1.3 million square kilometres. Our three regulated networks in Darwin-Katherine, Alice Springs and Tennant Creek provide power to about 185,000 people. The role of our electricity network is to transport electricity generation safely and reliably to customers, including via rooftop solar.

Every 5 years, the Australian Energy Regulator (AER) undertakes a review of our proposed expenditure, revenue and tariff structures of our regulated networks. Our next proposal is due in January 2023 and is for the 2024-29 regulatory period.

Purpose of this document

This document provides our stakeholders and the AER with a high-level summary of our method to forecast capital and operating expenditure. This includes our standard services offered to all customers, and our metering and one-off services which have separate prices.

The purpose is to provide early visibility of our methods and to show how we are evolving to align with the AER's expectations and 'best practice' in the industry.

A key objective is to encourage conversations and feedback on our approach before we submit our regulatory proposal. This includes in areas where our methods are maturing, and being implemented for the first time.

What is capital and operating expenditure

Figure 1 shows the activities we undertake to provide customers with reliable electricity services, and their relative contribution to total network costs over the last decade.

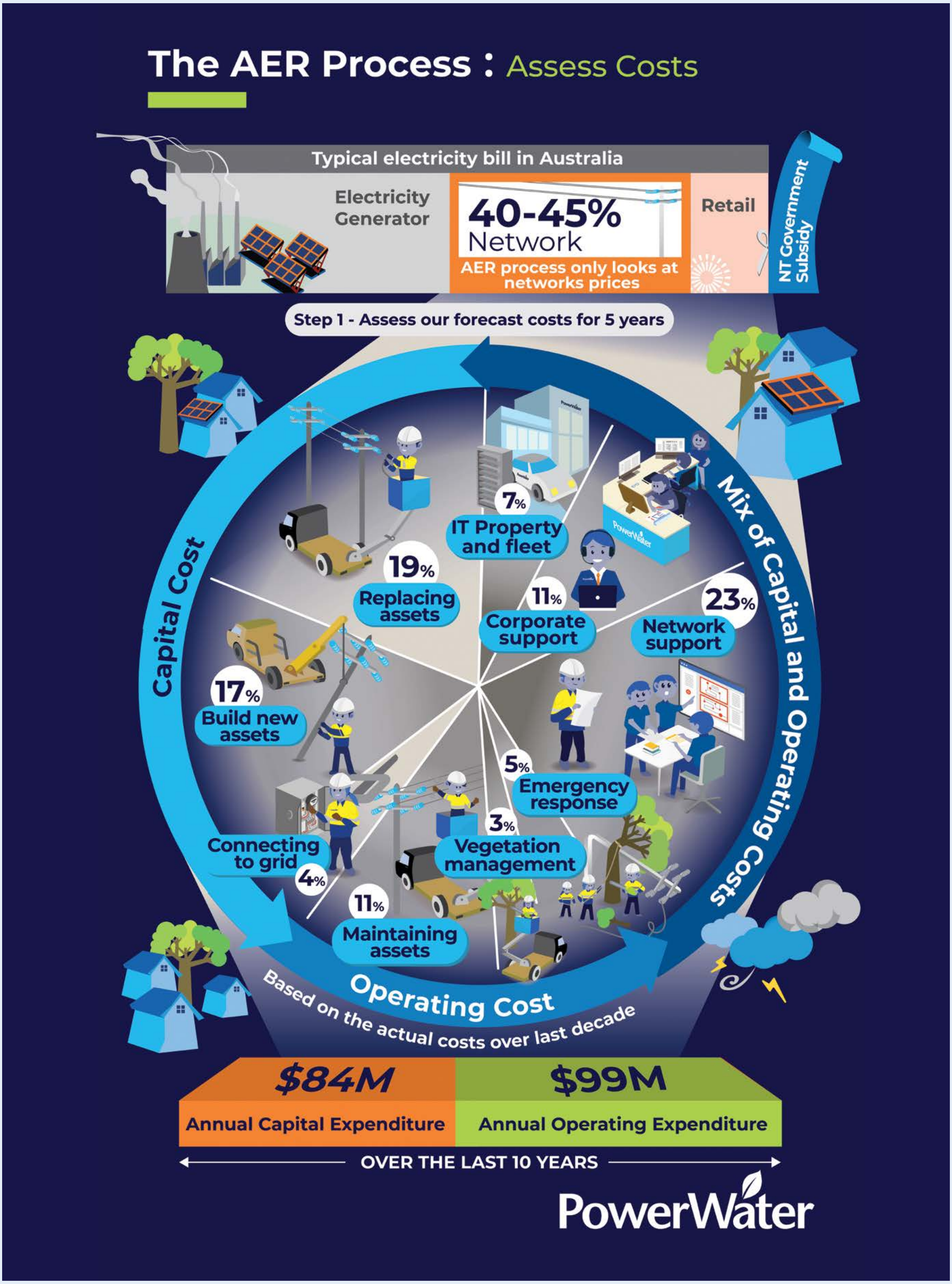
Capital expenditure relates to building or replacing assets that provide services over a longer period. This includes replacing network assets, building new network assets, and connecting customers to the network. Capital expenditure is recovered by Power and Water from customers over the expected life of an asset.

Operating expenditure relates to regular annual expenses such as maintaining assets, vegetation management and emergency response to outages. These costs are recovered from customers by Power and Water on a yearly basis.

Some activities have a mix of operating and capital expenditure. Like other businesses, we have Information and Communication Technology (ICT), property and fleet assets to support our network activities. Some of these costs relate to assets such as hardware, while others relate to regular expenditure such as ICT support. We also invest in new meters and incur operating expenditure to manage our metering functions.

Network and corporate overheads also support our network services. Network overheads include asset management activities we undertake to plan, control and manage the network. Corporate overheads including finance, legal, procurement and human resources to support activities across our electricity, water, sewerage services and gas lines of business. We allocate overheads to each line of business in accordance with our Cost Allocation Methodology. We also allocate these costs to capital and operating expenditure depending on the nature of the activity.

Figure 1 – Capital and operating costs over the last decade for our regulated business



Improvements to expenditure methods

We have been improving our forecast methods since our last regulatory determination. For the 2024-29 regulatory proposal, we have made further refinements to ensure total expenditure is prudent and efficient.

Strategic focus on the changing energy system

Our forecast methods are evolving to consider the longer-term strategic challenges and opportunities impacting our network and business.

The energy landscape is changing rapidly as renewable energy accelerates in our power system. The Northern Territory Government (NTG) has a goal of meeting 50 per cent renewable energy in the power system by 2030. The NTG's Darwin-Katherine Electricity System Plan will require our transmission network to transport large scale solar and batteries from renewable energy hubs. Our distribution network will also play a pivotal role in facilitating the export of small scale solar from our customers.

In Alice Springs, we are partners in a future grid trial that is testing a range of options to ensure small scale renewables can expand in our network without impacting customer reliability or affordability.

It is also important to start planning for the ageing of our network assets, many of which were built immediately after Cyclone Tracy and will be approaching the end of their technical life by 2030.

Our network planning approach is gradually evolving to develop longer term projections of drivers, and 10 year forecasts of projects and programs.

Stakeholder engagement

We pride ourselves on being responsive to our customers and playing our part in the NT community.

Until recently, customers had no formal input into our strategic decisions. This is a gap we have been addressing when developing our 2024-29 regulatory proposal. The proposal is an opportune time for customers to provide feedback as we set out a five year expenditure and revenue plan to the end of the decade.

We have developed an extensive engagement program to understand what matters to our customers, and to understand their values, vision, and priorities. This includes establishing a representative panel of customers in our Darwin-Katherine and Alice Springs regions (**see Figure 2**), what we have termed our "People Panel". **Figure 3** shows the collective vision of the People Panel on where Power and Water should be by 2030.

The panels provide an opportunity for deliberative engagement. Customers are given resources and freedom to provide feedback on their values, vision, and key priorities. Our expenditure forecast methodologies seek to provide a 'line of sight' between customer feedback and the forecasts proposed in the 2024-29 regulatory period.

In our discussions with our panels, we discussed the values that customers consider are important in our decisions. In particular, we discussed the trade-offs in values. While affordability was a central value of our customers, there was a recognition that the networks need to invest in the longer term health of the network and facilitate renewables in the energy system.

The feedback our customers have provided on values and priorities have been instrumental in the development of forecasts for capital expenditure. As noted in the next section, customer values and priorities have resulted in expenditure programs that were not initially in our bottom up forecasts.

Evolving to 'best practice' industry approaches

We are making significant improvements to our forecast expenditure method ahead of the 2024-29 regulatory proposal.

This includes a focus on developing a capital portfolio using tools such as risk quantification, in line with the expected approach of the AER and the practice of our peer networks in Australia.

We have also been refining our demand, energy and customer connection forecasts to better understand the impact of new technologies such as solar, batteries and electric vehicles.

Finally, we have been aligning our forecast methods to the AER's preferred approaches as detailed in their published guidelines and guidance notes.

In Alice Springs, we are partners in a future grid trial that is testing a range of options to ensure small scale renewables can expand in the network without impacting customer reliability or affordability.

Figure 2 – Alice Springs People Panel in April 2022

Figure 3 – People Panel's vision for Power and Water by 2030

Capital expenditure

In our last regulatory proposal, the AER and our stakeholders suggested improvements to our capital forecast methods. We have responded by implementing significant changes to our strategic planning, demand forecast methods, and risk assessment approaches. Our method for the 2024-29 proposal will be to identify long-term investment priorities, develop bottom-up plans based on need and options, and prioritise investments. A key goal is to have a 'line of sight' between our capital expenditure program and the priorities our customers have identified in engagement sessions.

Since our last proposal, we have significantly improved our expenditure forecasts methods for capital expenditure.

We have taken on board the feedback of the AER and stakeholders on issues such as risk quantification, demand forecasts and top-down prioritisation. We also recognise that the energy landscape is rapidly changing, and we need to think more strategically about the longer term.

In our 2021 Transmission and Distribution Planning Report (TDAPR) we identified longer term drivers of investment over the next 20 years. This included opportunities and challenges of moving to a renewable generation mix, including more household solar on the electricity system. We also discussed the ageing of our network assets and the impact of electrical vehicle uptake on our network.

The 2021 TDAPR also extended our planning horizon for distribution assets to 10 years to align to our transmission assets. We noted proposed improvements to our risk assessment approaches and demand forecasts.

We recognise that seeking funding from the AER for our expenditure plans to 2030 requires additional cross-checks, tools and evidence. Many of the projects included in our regulatory proposal would not be at a stage for progress through our capital governance framework. For this reason, we will be providing a deeper analysis of our capital expenditure forecasts for the regulatory proposal.

At a high level, there are three steps we will apply to developing the capital forecast expenditure for 2024-29, as seen in **Figure 4**.

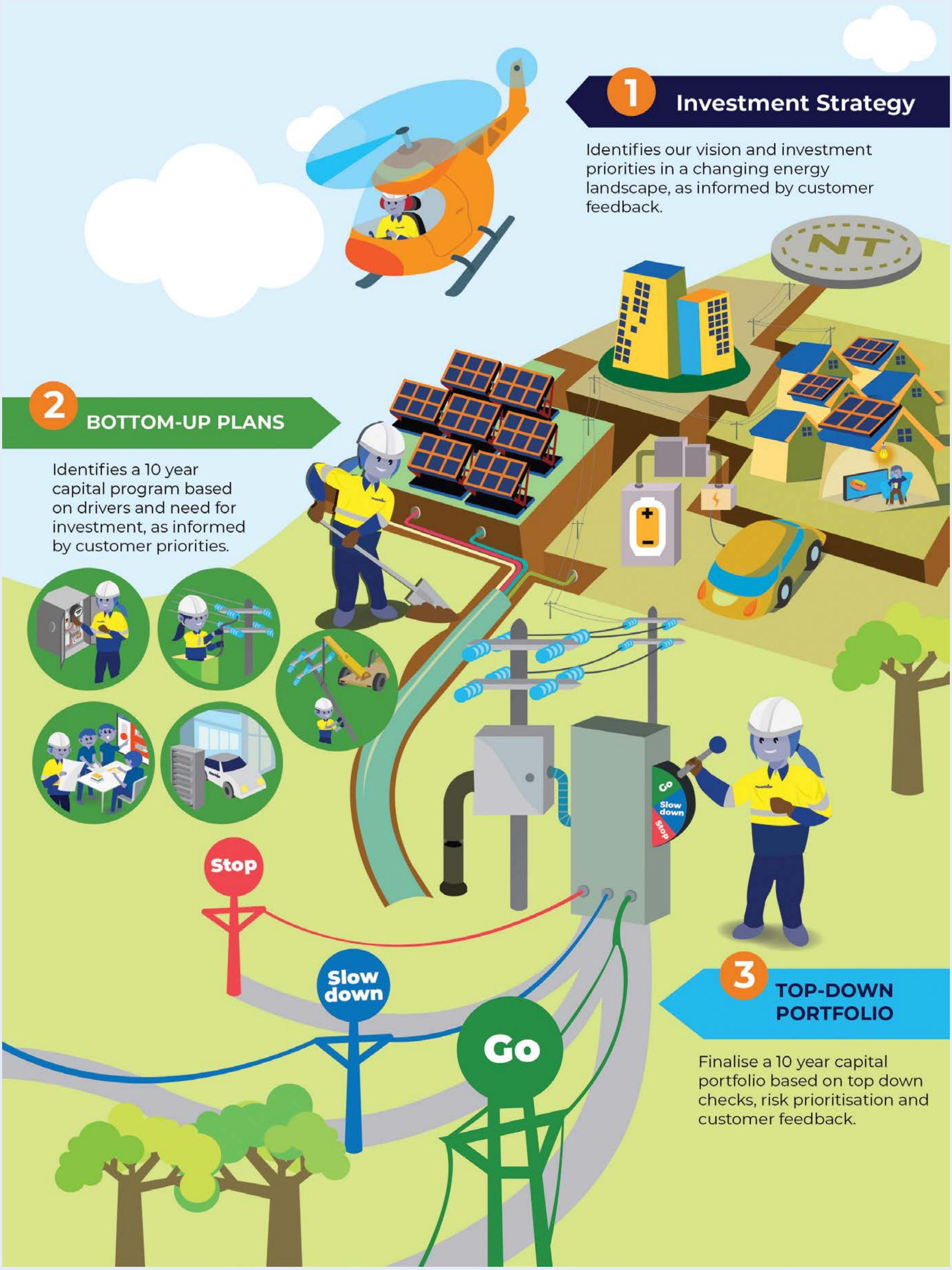
1. **Identifying strategy** – The starting point for our expenditure forecasts is to understand our changing environment over a longer-term horizon. Our strategy is informed by the feedback provided by our customers on values, vision, and priorities for investment.
2. **Bottom-up plans** – We identify key drivers of investment such as asset condition, growth in network usage, support from non-network assets, and overhead requirements. We then undertake needs and options assessment to develop a bottom-up list of projects and plans over a 10 year horizon.
3. **Top-down portfolio** – A portfolio view helps identify the optimal mix of projects and programs that provide best value, align with longer term investment priorities, and deliver customer preferences.

Our overall approach has carefully considered guidelines published by the AER including the Expenditure Forecast Assessment Guidelines and the Capital Expenditure Assessment Outline for Electricity Distribution. Our forecast method seeks to align to the guidelines by:

- presenting capital expenditure in the sub-categories nominated by the AER;
- ensuring our project assessment provides economic justification;
- undertaking checks such as benchmarking with peers, and comparisons to past expenditure;
- prioritising our programs through top-down analysis of priorities and capabilities; and
- using AER models to challenge our forecasts.

We have also considered the AER's Industry Practice Note on Asset Replacement Planning by applying its risk-cost assessment methods. We will also be presenting our ICT forecast to align with the approaches identified in the AER's guidelines including presenting our programs in recurrent and non-recurrent categories.

Figure 4 – Overview of the forecast capital expenditure method



Step 1 – Developing the investment strategy

The starting point of our forecast capital expenditure method is to understand the potential changes impacting our network in the long term, and to articulate strategic investment priorities. **Figure 5** shows the key steps in this process.

The investments we make today will be recovered from customers through network charges over a long period – spanning generations. It is vital that our investment portfolio is targeted at the future energy landscape and is 'right sized' to meet the needs of our customers now and into the future.

Our relatively small and isolated networks will face significant disruption over the next two decades. The urgent global need to reduce carbon emissions has fundamentally shifted energy production to renewables. The pace of change will accelerate as the NTG implements its plan to achieve 50% renewable energy by 2030. We also expect new sources of demand for our network services post 2030, including demand from electric vehicles.

The uncertainty and pace of change makes investment decisions more complex than ever. It is for this reason that our expenditure forecast approach for the 2024-29 proposal strategically focuses on the long term energy market in guiding our investment priorities. Below we discuss how our corporate vision and customer preferences help us articulate our investment priorities.

A. Corporate vision

As the essential service provider in the Territory, our purpose is to make a difference to the lives of Territorians. We need to play our part in enabling the economic goals of the NT, together with playing our part in progressing social issues such as reducing emissions.

To meet our purpose, we need to ensure our network is safe and reliable now and into the future. We need to connect new residential and business customers seamlessly and ensure the network can meet new demand for electricity. Increasingly, our network will be required to facilitate renewable energy by connecting new large solar farms and exporting household solar.

Customer service also lies at the heart of our purpose to make a difference to the lives of Territorians. We need to ensure our people and systems are responsive to the needs of our customers, and that we have diverse channels to communicate to customers.

With a relatively small population, we also need to ensure we live within our means. This means that we need to adapt to our changing circumstances with innovation and meet future challenges at smaller scale investments compared to other networks.

B. Customer values and priorities

Our engagement sessions with customers and stakeholders have sought to identify priorities for investment.

For example, our People Panel have told us that we need to facilitate and support solar, including piloting new technologies and community batteries.

They also wanted us to pursue options that smooth capital expenditure and prices over the long-term, and use advances in technology where possible.

These priorities help us articulate clear strategic investment priorities that underlie the capital forecast for the 2024-29 proposal.

C. Investment strategy

Our investment strategies will articulate our capital expenditure priorities over a 20 year period. It will bring together our corporate strategy and customer priorities to provide clarity on the focus of investment over the next 20 years.

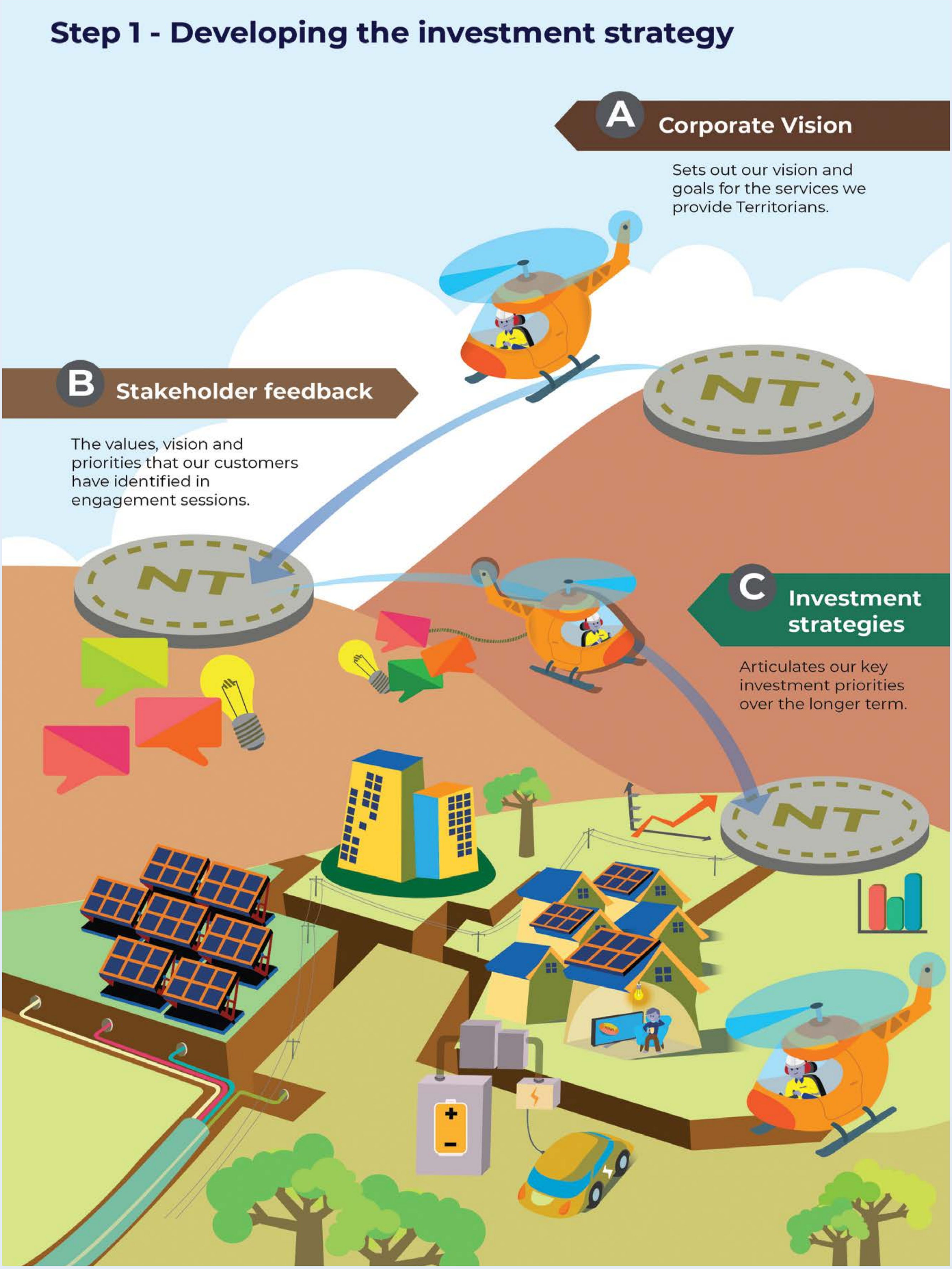
The strategy will identify future drivers of investment in a changing energy landscape. This involves examining internal drivers such as an ageing asset base, resource capability constraints in the NT, and ageing ICT systems.

We will also draw out the key external drivers that will change the way we operate our business including the shift to renewable energy, electric cars, increased economic growth in the NT, and increasing regulatory obligations.

From here, we will ask ourselves what our priorities should be over the next 20 years, given our corporate vision and customer feedback.

The articulation of investment priorities helps inform the way we develop our projects and programs and how we prioritise investments.

Figure 5 – Developing the investment strategy



Step 2 – Develop bottom-up plans

The next step in our capital forecast method is to identify a list of major capital projects and programs over the 2024-29 regulatory period.

Figure 6 outlines the process from screening drivers of investment, identifying project needs and solutions, and assembling a list of projects over a 10 year horizon.

This is a similar process to what we undertake yearly for our Statement of Corporate Intent (SCI) that we provide to our shareholder and the TDAPR. Our approach is to roll-forward existing plans and adjust for any changed circumstances including new major projects or programs.

For the 2024-29 regulatory proposal, we will be implementing additional tools such as risk quantification that have not previously been applied in our annual process. Our refreshed needs assessment for individual programs and projects will ensure our bottom-up forecast reflects the most current information. Finally, we will be forecasting non-network expenditure over a longer 10 year timeframe to align with the annual process for network investment.

A. Drivers of investment

Power and Water has an established asset management framework to identify drivers of investment.

Network asset condition

We replace or refurbish network assets which demonstrate deteriorated condition and pose material risks, or do not meet today's safety or environmental standards.

Our replacement program for the regulated network requires ongoing assessment of 45,000 poles, 7,000 kilometres of electricity conductor and 5,000 transformers.

A significant portion of these assets were installed in the years immediately following Cyclone Tracy in 1974. This means that over the next 20 years, we expect many of these assets will reach the end of their technical life and at this time may pose material safety, reliability or environmental risk.

We regularly monitor the health of our assets through our inspection and maintenance programs as well as analysis of outages. We also monitor the age of the population by technology type to identify long term replacement needs.

We identify assets that may require replacement or refurbishment over a 10 year planning horizon.

Growth in network usage

There are three key drivers of capital expenditure on new network assets.

Traditionally, the key driver has been an increase in demand at peak times of network use. In the NT, this is usually in the summer period where hot conditions lead to greater air conditioner use. Higher demand may be triggered by a single large customer connecting to the network, or increased demand from multiple customers.

We develop ten year forecasts of peak demand at a local level for transmission feeders, large substations and high voltage feeders. We consider historical trends, forecasts of population and economic growth, uptake of solar and batteries, and new committed connections including major customers. We assess if there is sufficient capacity to meet the forecast demand in electricity at peak times at each level of the network. We are currently in the process of improving our forecast demand process to better estimate solar, batteries and connections.

A second driver of investment in new assets relates to meeting prescribed reliability standards. This is either for average reliability standards or to improve reliability for customers in worst impacted rural areas.

A new driver of investment over the last five years is improving the network's ability to manage export solar energy from customers' rooftops. Our investment strategies are indicating this will be a key focus over the next decade. We are reaching limits on our ability to reliably manage the export of solar across all parts of our network, and these limits will amplify with a forecast doubling of solar installations over the next decade.

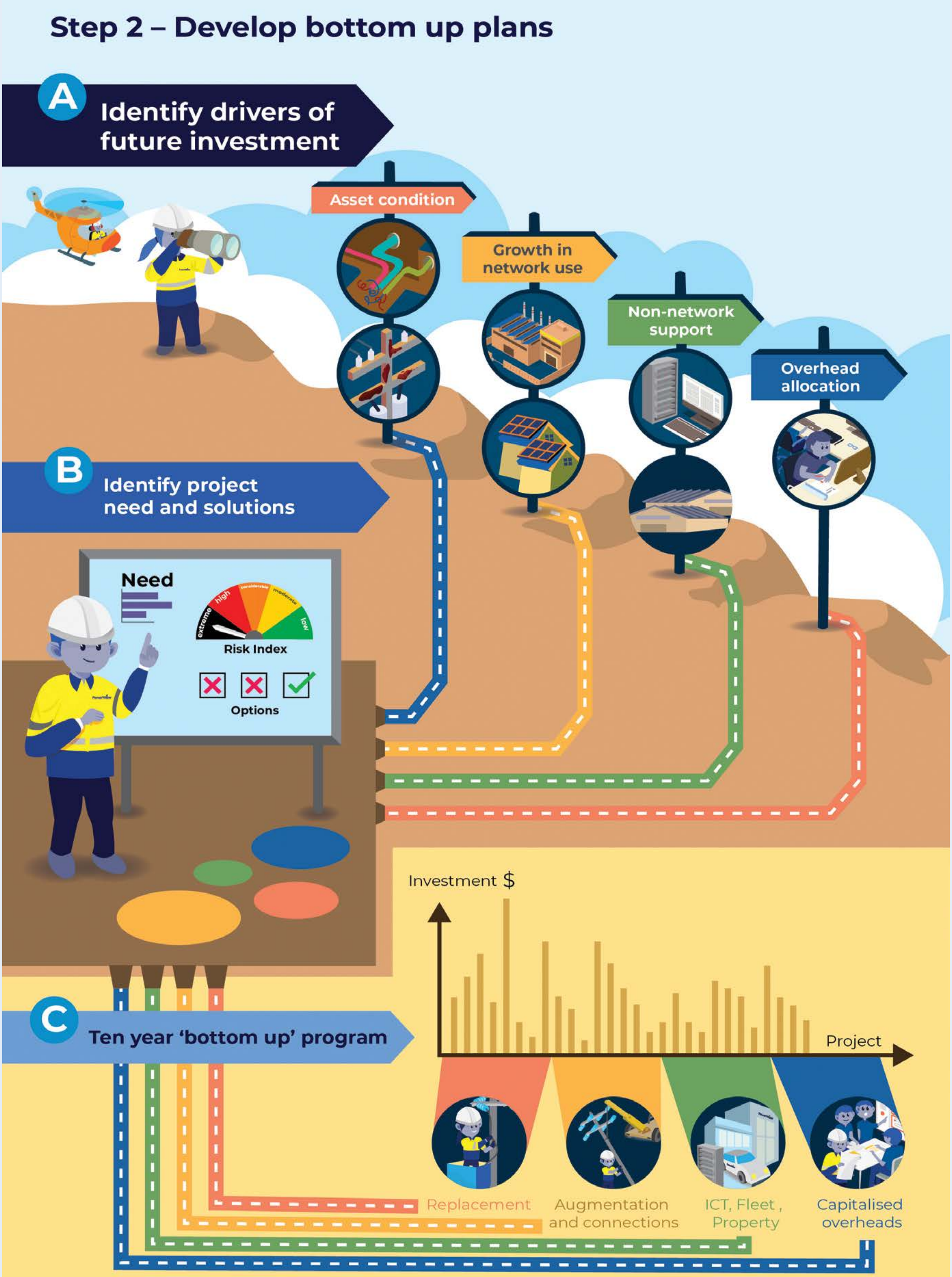
Non-network assets

We require non-network assets such as ICT, fleet and property to efficiently run our business. We also require capital expenditure to replace and install new meters.

Our ICT systems require a significant refresh to ensure we meet our regulatory obligations, ensure cyber-security, and provide services that reflect customer expectations in a digital world.

Our journey to refresh our ageing ICT systems commenced in the current period. Our strategy is to sequence our ICT system refresh to meet the most pressing priorities, and to ensure that the solutions are efficient for our relatively small customer base.

Figure 6 – Develop bottom-up plans



Our forecast method for ICT will closely follow the AER's Guidance Note on ICT assessment. We will forecast recurrent expenditure such as hardware refreshes and software upgrades. Separately we will forecast non-recurrent expenditure such as new or upgraded systems.

Like any business we need commercial buildings and depots to house our staff. Our forecast approach seeks to identify the cost of properties we lease such as our head corporate office. The forecast ongoing lease costs are capitalised. We will also forecast refurbishment or replacement costs on buildings we own. Similar to property leases, we forecast ongoing lease costs of the vehicles that our field staff use to travel to and manage the network.

We also forecast capital expenditure to deliver our metering responsibilities. Unlike the National Electricity Market, our network is the metering provider, coordinator and data provider for all electricity customers in the NT.

Metering prices are calculated separately to standard services, of which a key component is replacement and new meter capital expenditure. We forecast replacement needs based on the condition of meters. We also forecast meters for new customers and customer driven meter changes such as solar installations. We use our cost allocation methodologies to allocate non-network capital expenditure and network and corporate overheads to the metering services.

Allocation of network and corporate support

Building electricity networks requires back-office support in the form of activities like network forecasting and planning, procurement, works scheduling and project management. A range of corporate support activities such as finance, legal, procurement and human resources are necessary to support these activities. Similar to all networks these costs are allocated to capital and operating expenditure in accordance with accounting standards. This is an area we are currently reviewing to ensure we align to best practice with other networks.

The assessment for overheads uses the base year, step and trend method described in the next chapter on forecast operating expenditure methods. The portion allocated to capital expenditure is dependent on the allocation method, which is turn reflects the relative level of capital and operating expenditure.

B. Identify project need and solutions

Based on our screening of drivers, we then undertake an assessment of need and options at an individual project or program level. For example, an analysis of a type of pole may indicate worsening condition across the population that could give rise to safety risks, triggering a needs and options assessment.

For the 2024-29 regulatory proposal, we will be improving our annual process for identifying needs and options. Firstly, we will be bringing forward some of the detailed project assessment we usually undertake closer to the time of investment under our capital governance process.

Secondly, we will be using risk quantification to conduct economic appraisal of the costs and benefits of investments. This is a relatively new approach for Power and Water and follows extensive feedback from the AER in our last proposal. By providing a quantitative basis for valuing risks, we can more consistently consider needs across the capital portfolio.

We identify the probability of a risk occurring, and the consequence such as safety, reliability, environment and other factors consistent with our Corporate Risk framework. Such an approach allows us to defer investment and improve affordability, where the risks can be managed appropriately.

The key values in our new approach including health and safety of workers and the public, compliance, direct financial costs, environmental, service delivery and customer experience. Each of these values have a dollar impact based on whether the consequence is insignificant, minor, moderate, major or severe.

The risk is measured as the probability of the event occurring, multiplied by likelihood of a consequence from the event multiplied by the value of that consequence.

A key element of our analysis of projects and programs is to analyse network and non-network options that most efficiently address the need. We have made significant improvement in our project planning approach for non-network alternatives. In 2020, Power and Water published a Demand Side Engagement Strategy which is targeted at notifying and working with non-network providers to find credible and less costly solutions to traditional network investment.

More broadly, our options assessment considers if there are efficient operating expenditure solutions that can address the issue. For example, we examine whether corrective maintenance could be used to address an issue with a network asset rather than refurbishment or replacement.

C. Ten-year project list by AER category

The last stage is to assemble a list of major projects and programs into a summary form including details such as cashflow, volumes, scope and description of need. The projects are grouped by AER categories.

- Replacement capital expenditure is directed at addressing condition drivers, through replacement or refurbishment. **Figure 7** is an example of a replacement program directed at replacing rusted poles in Alice Springs.
- Augmentations relate to growth in energy usage including managing solar. Connection expenditure is a sub-component where the works are to connect a single customer. Our connection policy is used to calculate the capital contribution of the customer.
- Non-network investment relates to ICT, property and fleet assets and leases. It also includes metering expenditure which is subject to a separate price under the regulatory framework.
- Capitalised overheads relate to the portion of network and corporate costs allocated to capital expenditure under our accounting and cost allocation methods.

We also forecast capital expenditure to deliver our metering responsibilities. Unlike the National Electricity Market, our network is the metering provider, coordinator and data provider for all electricity customers in the NT.

Figure 7 Alice Springs rusted pole

Step 3 – Top-down portfolio

As part of the last distribution determination, the AER recommended we apply top-down approaches to prioritise our bottom-up list of projects. This recognises that businesses choose between investments, and this generally occurs closer to the time of investment.

While we have sought to implement the AER's recommendations, we still consider that the business case is the primary evidence to assess the veracity of capital expenditure forecasts. This is particularly relevant where the business case embeds a robust risk quantification approach within the inherent decision making.

Nevertheless we are mindful that checks are useful to ensure the portfolio can be further verified in terms of delivery and as points of comparison with other high level models. We also consider that a prioritisation process may provide insights into the overall change in total risks.

Figure 8 describes the three key steps to develop a final 10 year portfolio for our capital expenditure forecasts in the 2024-29 regulatory period. Our approach reflects that we are still maturing as a business in terms of tools to prioritise investments.

A. Checks

Our first step will be to ensure the bottom-up list of projects can be delivered with our resource availability. In the last two years, we have not delivered the forecast capital program due to overlapping priorities such as connection of large renewable generators, resource and process constraints, and issues with the Covid pandemic. This has meant that we have had to prioritise investments and accept more risk.

We have recently implemented changes that should improve our ability to deliver the program in the short term, but we recognise that it may take some time to fully implement systematic changes. A key element of our forecasting method will be to understand our ability to uplift our delivery into the future to meet the needs-based program. This will be something we discuss openly and transparently with our customers and stakeholders.

Our methods also identify projects which are material but are highly uncertain in terms of timing, scope or funding arrangements. These are termed 'contingent projects' in the regulatory framework and are excluded from the allowance. We will be proposing triggers for projects that meet the thresholds and criteria in the NT National Electricity Rules.

A further check of the bottom-up program is to compare our forecast to AER models and category benchmarks. While top-down benchmarks are problematic for a network of our small scale and unique climate, we recognise that peer analysis can provide insights at a category level. For example, we intend to use the AER's "repex model" to assess if our forecasts for asset classes are similar to predicted levels in the AER's model. We will also compare metrics such as fleet per employee with our peers.

While we consider benchmark models have a place in identifying potential issues, they are not sufficiently granular to develop a forecast. For example, the AER's repex model is an age-based prediction model that cannot reflect the specific condition of assets. Further, the model calibrates the expected age of assets based on recent delivery levels. This means that low levels of past replacement can lead to unrealistic expectations of asset life. Our approach will seek to compare our forecasts to the AER's prediction and assess if there are reasons why our business case shows a different level of expenditure.

The final check is to ensure that we have a clear 'line of sight' between our bottom-up list of programs and the priorities identified by our customers. For example, our People's Panel have provided preferences on the types and level of investment to facilitate an increase in renewables on the network.

B. Prioritisation

Power and Water has a corporate prioritisation process to guide the relative speed and sequence of investments across electricity, gas, water and sewerage. For the 2024-29 proposal, we will be applying a bespoke prioritisation method for our list of bottom-up projects that help rank projects.

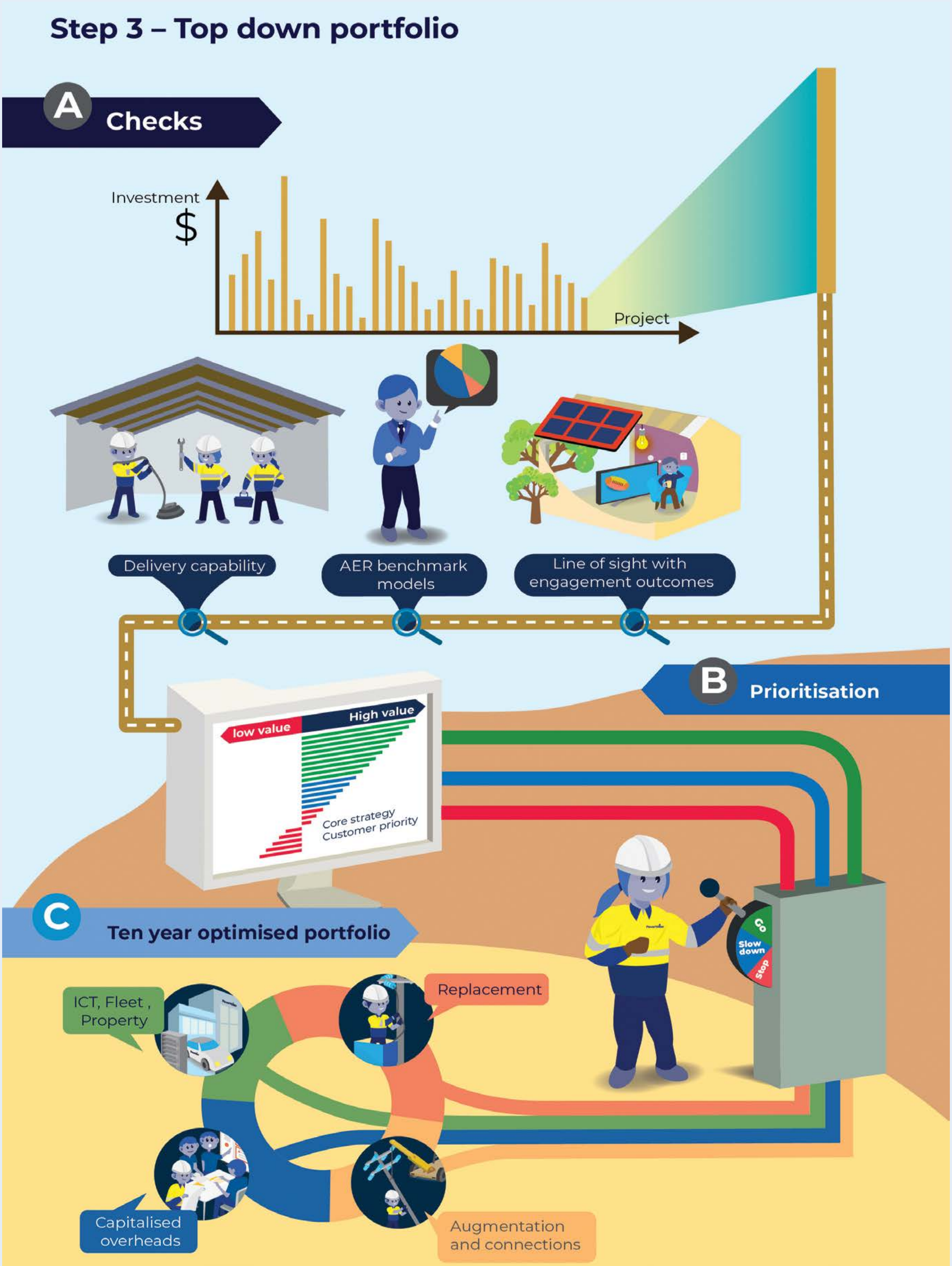
We expect to leverage our risk quantification method to identify the relative risk of projects or programs, and to provide a quantitative basis for understanding the risk at a portfolio level.

We will also be considering the broader investment priorities identified in our investment strategy in Step 1. For example, we would need to consider the impact of deferring replacement programs in the context of an ageing asset base. Finally, our prioritisation approach will need to consider how customers see the main priorities of the investment program, for instance, the need for the network to facilitate more household solar exports.

C. Top-down portfolio

The final phase is to develop a master list of projects and programs that reflect the outcomes of the checks and prioritisation approach. The projects are grouped by AER category including replacement, augmentations and customer connections, non-network, and capitalised overheads

Figure 8 – Top down portfolio



Operating expenditure

We will apply the AER's preferred method to forecast operating expenditure. This involves establishing an efficient base to forecast ongoing costs, and applying trend adjustments and step changes for new factors impacting the business. A key focus of our approach is to understand our future operating environment, and to align with our customer's vision for the future.

Operating expenditure are routine activities that do not relate to the design and construction of assets. We group these routine activities into:

- Maintenance – Inspecting, maintaining and repairing network assets.
- Vegetation management – Maintaining vegetation around our assets to reduce safety hazards and interruptions to supply.
- Emergency response – Fault and emergency repairs and supply restoration caused by events such as storms and equipment failures.

We also incur maintenance and operating costs associated with our non-network assets including ICT, property, and fleet.

In addition, we have network and corporate overheads to support our network activities. As described in the section on forecast capital expenditure methods, we use accounting standards to determine if these costs are included as operating or capital expenditure. Our corporate costs are allocated to lines of business activity according to the driver in our Cost Allocation Method.

Figure 9 identifies our overall approach to forecast operating expenditure. The base year, trend and step method depicted in the diagram is consistent with the AER's preferred method in its Expenditure Forecast Assessment Guidelines.

1. Base Year – Operating expenditure tends to be recurrent from year to year. This means that the most recent expenditure generally provides a good indication of future levels. Our forecast method will use the audited Financial Year 2022 (FY22) actual operating expenditure as the base year. Adjustments for non-recurrent expenditure and top-down checks of efficiency will be made to ensure it is appropriate to forecast future costs.

2. Trend – Consistent with the AER's approach we will apply a rate of change to the base year to account for changes in input prices, work activity from increasing network size, and productivity.

3. Step changes – We will identify changes impacting our business environment that will change our costs. Consistent with the current period we will also add or remove step changes for annual efficiency adjustments if required.

In applying a mechanistic approach, we will also consider the 'big picture' of how our network will need to adapt to major changes impacting the energy industry, and internal drivers such as an ageing asset base and the need to refresh our ICT systems.

Our investment strategy outlined in the forecast method for capital expenditure will be a key touchpoint for our method to forecast operating expenditure. For example, we will consider the maintenance expenditure and resources that would be needed to facilitate investments to unlock small scale renewables.

The ultimate purpose is to ensure that we have sufficient resources to efficiently realise the future vision of our customers.

We note that Power and Water develop separate prices for metering services. Our cost allocation method establishes the operating expenditure that relates to metering services such as reading meters, together with overhead allocations for other costs. Our method to forecast operating expenditure is consistent with the base year-step-trend approach.

Figure 9 – Operating expenditure forecast approach

Step 1 – Establish a Base year amount

The adjusted base year amount is the most important element of our forecast method. **Figure 10** shows that we use the revealed audited costs of a nominated financial year (base year), adjust for non-recurrent costs, and apply a top-down check of the sufficiency and efficiency of expenditure. In some cases, we will exclude a cost item from the base year and develop a separate forecast.

A. Identify the base year

The last year of actual operating expenditure is likely to be a good indication of future levels. This is because operating activities do not vary significantly from year to year (what we term "recurrent").

FY23 will be the last financial year before the final distribution determination, but audited financial accounts for FY23 will not be available at the time of the proposal.

We will use the FY22 audited operating expenditure to derive the base year, given we submit our proposal in January 2023. We may choose to adopt audited FY23 expenditure to support a revised forecast at the time of our revised proposal, depending on any material changes between years.

B. Adjustments for non-recurrent costs

While operating expenditure is generally recurrent, there may be some activities in a base year that are one-off costs or atypical in cost levels. These costs need to be adjusted to establish a base that is indicative of future ongoing costs.

We will examine the activities we undertook in the base year for each of our major cost categories of maintenance, vegetation management, emergency response, non-network, and corporate and network overheads. The purpose will be to identify costs incurred in the base year that are likely to materially vary in the future.

If required, we will adjust for one-off events and unusual weather activity that directly impact categories of operating expenditure.

More generally, we will also assess if the base year expenditure amount requires adjustment for changes in service classification. We will also consider if adjustments are required due to atypical split between capital and operating expenditure in the base year.

In our regulatory proposal, we will be clear on what categories and activities of costs have been adjusted in the base year.

In some cases, we will develop a specific forecast of an activity that we exclude from the base year. This includes debt raising costs, where we will apply a benchmark debt raising unit rate to the regulatory value of debt.

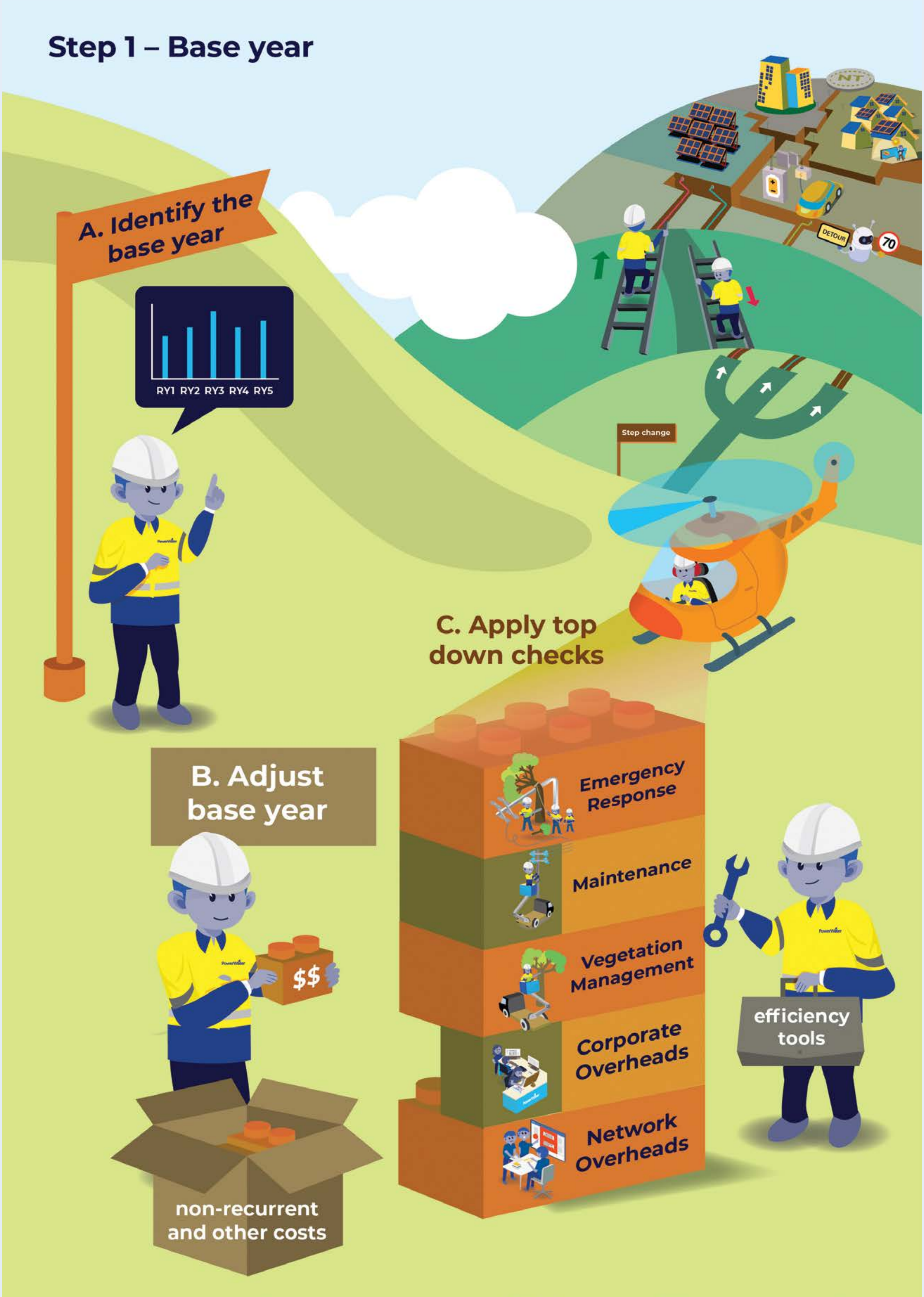
C. Top-down check for sufficiency and efficiency

The last step is to assess whether the base amount year, after removing non-recurrent costs, represents a sufficient or efficient level of expenditure or whether further adjustments are necessary.

It is difficult to directly benchmark Power and Water with other networks in Australia. We have many unique characteristics that increase the cost of delivering services to our customers, that are not experienced by other networks to the same degree. This includes:

- We have half the customers of the smallest network in the National Electricity Market, resulting in a scale disadvantage.
- We are unique in that none of our regulated networks are connected to the NEM. This creates a substantially different approach in our role of planning, managing and operating three separate networks that have no interconnection and span vast distances. In Darwin-Katherine, we are also the transmission network and have a much greater, interdependent role in the strength and stability of the three power systems.
- Extreme heat and humidity has an impact on the productivity of our field force. Further, in the top end of Australia, we frequently have extreme weather including storms and cyclones.
- We have high labour costs and our remoteness makes it difficult to attract and retain skilled labour.
- Our network operations are subject to more wear and tear from the weather and exposure to animals and insects.

Figure 10 – Step 1 of operating expenditure method – the base year process



The challenges around making the necessary adjustments for meaningful benchmark comparisons are well documented in the last distribution determination.

These challenges extended to data quality and integrity issues, particularly with estimating long term historical regulated expenditure. We have been examining our approach to cost accounting for regulatory purposes and have made significant changes to ensure moving forward, allocations to cost categories are more comparable.

While differences with our business to others make benchmarking complex, we will also examine benchmarking data at a category level to provide an informed view of activities where expenditure appears high or low.

We will also undertake an internal examination of our base year to identify efficiencies. This will involve looking at our performance in the past and assessing if there were any opportunities for efficiencies which will reduce the base year amount.

Step 2 – Trend

The next step in our process will be to calculate the trend in forecast operating expenditure from the adjusted base year expenditure amount. This reflects changes in workload levels, prices of materials and labour, and productivity compared to our base year.

We will calculate a trend adjustment for each year from FY23 to FY29 using the AER's rate of change formula. The three factors depicted in **Figure 11** are:

- Input cost escalation – We use materials, labour and contractors to undertake operating expenditure activities. While we automatically include inflation in our forecasts, the price of the inputs may be higher or lower depending on demand. We will use independent sources to provide an estimate of materials, labour and contract inputs to calculate the rate of change.
- Output growth – As our network and customer base expands, we have to perform more activities such as maintenance and customer service. This means that our costs will likely increase from the base year. We will apply the AER's calculation which includes change in customer numbers, energy demand at peak times, and line length.
- Productivity growth – Our customers would expect us to improve productivity over time through technology advances, and improved processes. We will likely use the AER's preferred approach to use industry estimates to establish the expected productivity growth but will also consider individual circumstances.

Step 3 – Step changes

Step changes are a forecast change in operating expenditure which is not captured in either the base year expenditure amount or the trend adjustment. They are driven by expected material changes in our business environment such as those depicted in **Figure 12.**

We will use the criteria in the AER's Expenditure Forecast Assessment Guidelines to identify potential step changes.

This includes identifying new obligations in NT and national regulations. Our organisation has been adapting to material changes in our regulatory obligations. Significantly, our ongoing transition to national electricity regulation requires an uplift in resources and systems to comply. We will seek to identify new obligations and provide detailed information on the efficient costs to comply.

We will also identify step changes where operating expenditure is a more efficient solution than investing in capital expenditure. A good example is where our options assessment for a network constraint demonstrates that a demand management solution is a more efficient option than capital expenditure.

A focus of our upcoming engagement with stakeholders and the AER will be on step changes that give effect to customer preferences on customer service and facilitating more rooftop solar in our network.

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Figure 11 – Step 2 of the operating expenditure method – trending the base year

Figure 12 – Step 3 of the operating expenditure method – add or remove step changes

PowerWater

Power and Water Corporation

Level 2, Mitchell Centre
55 Mitchell Street, Darwin
Phone 1800 245 092

powerwater.com.au

@PowerWaterCorp