Attachment 9.02

Operating expenditure step changes

31 January 2023

PowerWater

Contents

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
BST	Base Step Trend
C2M2	Cybersecurity Capability Maturity Model
DER	Distributed Energy Resources
DKESP	Darwin-Katherine Electricity System Plan
DMS	Distribution Management System
DNSPs	Distribution Network Service Providers
DOE	Dynamic Operating Envelope
DTF	Department of Treasury and Finance
E-CAT	Electricity Category
EIP	Electricity Industry Performance
EMS	Energy Management System
GPS	Generator Performance Standards
ICT	Information and Communications Technology
MIL	Maturity Indicator Level
NER	National Electricity Rules
NIST	National Institute of Standards and Technology
NTC	Network Technical Code
NTG	Northern Territory Government
OMS	Outage Management System
Opex	Operating Expenditure
OT	Operational Technology

Term	Definition
RIT	Regulatory Investment Test
SCADA	Supervisory and Control Data Acquisition
SLACI Act	Security Legislation Amendment (Critical Infrastructure) Act
SLACIP Act	Security Legislation Amendment (Critical Infrastructure Protection) Act
SOCI	Security of Critical Infrastructure
SoNS	Systems of National Significance
SP	Security Profile

Overview

In developing our opex forecasts, we have considered the changing environment and regulatory framework in which we operate. Customer expectations around the network being able to accommodate more renewables, batteries and electric vehicles, coupled with obligations stemming from our recent move to the national regulatory framework, are imposing new costs on our business. These costs are not included in our base year and require modest increases to our annual expenditure.

Our proposed step changes

We have adopted a base-step-trend (**BST**) approach to forecasting operating expenditure for the next regulatory period. In our BST approach, we use 2021/22 as the base year. From time to time, we forecast increases in operating expenditure (**opex**) that are not captured in the base year or the rate of change. When this occurs, we seek recovery of these costs through an opex step change in accordance with the NT National Electricity Rules (**NER**).[1]

Without a step change, we would otherwise not be provided with a reasonable opportunity to recover at least our efficient costs of providing standard control services and/or complying with our regulatory obligations.

In the next regulatory period, we forecast we will spend around $10.4 million per annum on step changes across four areas:

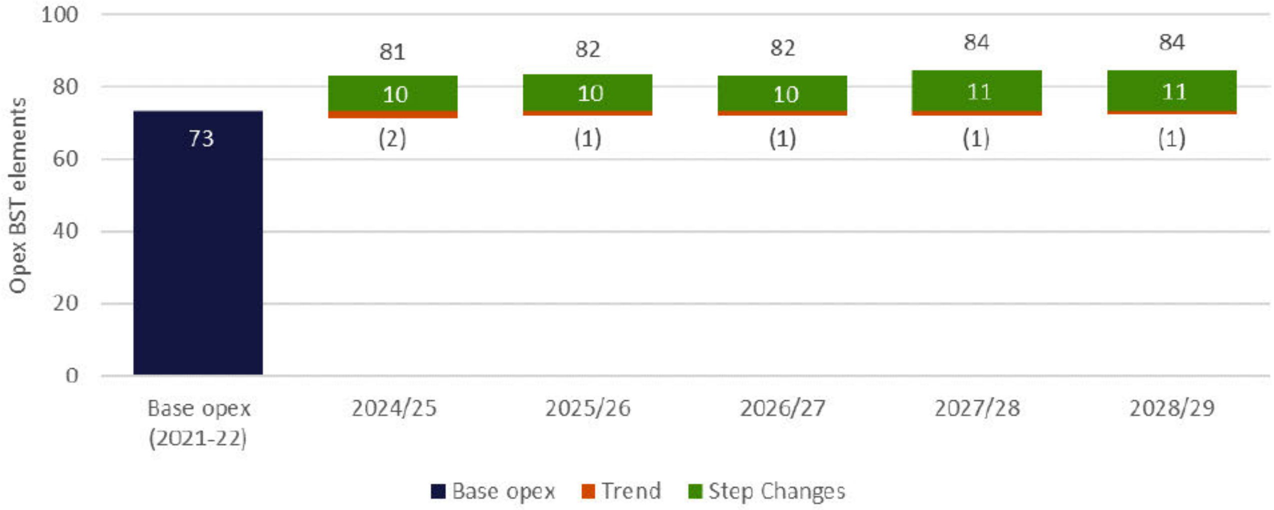
- Meeting technology and regulatory requirements:
  - Cyber security
  - Regulatory obligations
  - Cloud migration
- OT Capability Uplift Program
- Future Networks
- Insurance

All dollar values presented in this Attachment are in real 2024 dollars unless otherwise stated.

Figure OV.1 shows the overall impact of these step changes on our SCS opex forecast. Step changes are allocated in accordance with the Cost Allocation Methodology (approved by the Australian Energy Regulatory (**AER**) to SCS and Alternative Control Services (**ACS**). The allocation to ACS is shown in Attachments 13.01.

1 NT NER clause 6.5.6

Figure OV.1: Impact of step changes on SCS opex forecast ($ million real 2024)



A breakdown of the SCS opex forecast for each of the step changes by year is shown in the following table.

Table OV.1: Allocation of opex step changes to SCS opex by year ($ million real 2024)

Opex step change	2024/25	2025/26	2026/27	2027/28	2029/29	Total
Meeting technology and regulatory requirements						
– Cyber security	0.7	0.9	0.9	0.9	0.9	**4.4**
– Regulatory obligations	1.1	1.4	1.1	1.3	1.0	**6.0**
– Cloud migration	0.8	0.8	0.8	0.8	0.8	**4.0**
OT capability uplift	4.0	4.0	2.8	4.0	4.0	**18.8**
Future network	2.3	2.0	3.2	3.3	3.4	**14.1**
Insurance premium	0.7	0.8	1.0	1.1	1.3	**4.9**
Total allocation to SCS opex	**9.7**	**10.0**	**9.8**	**11.4**	**11.4**	**52.2**

Forecasting requirements

NT National Electricity Rules

The NT NER provides for a distributor to include in its revenue proposal an allowance for the total forecast operating expenditure for each year in the regulatory period. The distribution network service provider's forecast is required to reflect what the distributor considers is needed to achieve the operating expenditure objectives.[2]

2 NT NER clause 6.5.6(a). These are referenced in Attachment 9.01.

The Australian Energy Regulator (**AER**) is required to accept a forecast that reasonably reflects the requirements to achieve the operating expenditure criteria.[3] The operating expenditure criteria are that the forecast reflects:

1. The efficient costs of achieving the operating expenditure objectives.
2. The costs that a prudent operator would require to achieve the operating expenditure objectives.
3. A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In summary, therefore, while step changes contribute to the build-up of the opex forecast, the distribution network services provider's proposal (and the AER's assessment) is by reference to the application of the NT NER to the opex forecast as a whole.

Expenditure Forecast Assessment Guideline

AER has recently published an updated Expenditure Forecast Assessment Guideline.[4] Section 4.3 states:

> *Step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria.*

AER requires that such step changes should not double count costs captured elsewhere in the forecast.

Section 2.2 describes how the AER expects to assess step changes associated with new regulatory obligations and capex/opex trade-offs. For capex/opex trade-offs, AER states that it will assess whether the substitution is prudent and efficient. For new regulatory obligations, the AER provides a non-exhaustive list of the matters that it will consider. These include:

- Whether the obligation is binding.
- When it occurs and when the distributor can be expected to incur expenditure.
- What options were considered and whether the selected option is efficient.
- Whether the cost can be met from existing allowances.

While the guideline refers explicitly to how the AER will assess step changes that are driven by regulatory obligations and capex/opex trade-offs, the AER has applied its assessment more broadly, as is required of it under the NT NER. An example, which we refer to in a later section, is increases in distributors' costs for insurance, which are externally driven changes in circumstances resulting in largely unavoidable increases. In its recent determinations for Victorian distributors, the AER has accepted forecasts of such increases as step changes, in that they are not otherwise captured by 'rate of change' parameters.

In this document, we propose prudent and efficient opex step changes consistent with the objectives and criteria in the NT NER.

All dollar values in this Attachment are in real 2024 terms unless otherwise stated.

3 NT NER clause 6.5.6(c)

4 AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution,* August 2022

Changes from our Draft Plan

During our customer engagement program, we were in the early development stage of our opex forecasts. We discussed our initial proposed step changes with customers to get feedback on the merits and drivers of each.

Responding to the feedback received, we removed and amended some of the proposed step changes discussed in our initial information sessions and contained in our 2020-2025 Draft Plan, and we have added others where it is necessary to do so.

Removed step change

The Alice Springs People's Panel expressed concerns with closure of shopfronts and restricted ability for face-to-face communications with staff. The Draft Plan included an opex step change for new systems and processes to improve customer service. Since then, we have engaged with retailers and considered how to most efficiently address this concern.

We are now confident we can make a positive impact on the customer experience, working more closely with our retailers, within the current level of staffing. We consider any improvements to customer service such as improvements to community engagement and information provision can be absorbed, and therefore have removed the step change.

New step changes

Since the Draft Plan we have identified a number of additional increases required in the next regulatory period. We have therefore introduced new step changes reflective of the following drivers of costs:

- In line with other distribution network services providers, we are improving our cyber security resilience and will increase our security profile from security profile 1 (which we will achieve by the end of the current period) to security profile 2 by the end of the next period. More information is provided in section 1.
- Developing greater regulatory expertise, engagement and ensuring compliance with our regulatory obligations. More information is provided in section 2.
- Consistent with other electricity networks, our insurance costs have risen steeply since 2021/22. We expect them to continue rising, reflecting changes in the economy and greater risks due in part to the effects of climate change. More information is provided in section 3.
- A number of our existing and preferred new Information and Communications Technology (**ICT**) systems will not be supported by our vendors as on-premise solutions (our preference). We will therefore need to establish a small cloud footprint to host a number of our systems. More information is provided in section 4.
- The development of new and enhanced Operational Technology (**OT**) capabilities to embed and make effective use of our operational and control systems implemented as part of the OT Capability Uplift Program. More information is provided in section 5.

Engaging with AER

We have engaged with the AER in relation to a number of the proposed step changes and the drivers on our business. We will continue to engage with the AER and other stakeholders throughout the regulatory review process, to provide updated information as it becomes available.

1. Cyber security

In response to heightened cyber security and critical infrastructure concerns the Federal Government recently introduced new legislative obligations to ensure the physical and electronic security of Australia's critical infrastructure. This includes electricity networks. We are now required to increase our cyber security capability significantly to achieve and maintain the necessary practices and anti-patterns.

1.1 Why a step change is required

1.1.1 Legislative driver of step change

In response to heightened cyber security and critical infrastructure concerns, in 2018 the Federal Government passed the *Security of Critical Infrastructure (***SOCI***) Act*, which introduced obligations in the electricity, gas, water and ports sectors to ensure the physical and electronic security of Australia's critical infrastructure.

Since the SOCI Act was introduced, there have been two key legislative changes requiring us to increase our cyber and physical security capabilities above the requirements in the initial SOCI Act:

1. In December 2021, the *Security Legislation Amendment (Critical Infrastructure) Act* (**SLACI Act**) commenced. Relevantly, it amended the SOCI Act to:
   - Provide a regime for the Commonwealth to receive reports in relation to cyber security incidents.
   - Provide a regime for the Commonwealth to respond to serious cyber security incidents.
2. In April 2022, the *Security Legislation Amendment (Critical Infrastructure Protection) Act* (**SLACIP Act**) commenced. It further amended the SOCI Act to introduce additional measures relevant to our business:
   - A new obligation for responsible entities to create and maintain a critical infrastructure risk management program. Sector-specific Risk Management Program Rules[5] are now available. As an entity responsible for critical infrastructure, we must comply with these rules.
   - [redacted]
   - [redacted]
   - [redacted]
   - [redacted]

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5 Cyber and Infrastructure Security Centre/Department of Home Affairs, *Risk Management Program Rules*, Rule 1.

6 [redacted]

7 Cyber and Infrastructure Security Centre/Department of Home Affairs, *The Enhanced Cyber Security Obligations Framework*

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

1.1.2 Expected target for Power and Water (Electricity networks)

Responsible entities for critical infrastructure assets must:

- Within six months of the commencement of the Risk Management Program Rules, ensure that their risk management program includes details of a risk-based plan that outlines strategies and security controls as to how cyber and information security threats are being mitigated.
- Within 18 months of the commencement of the Risk Management Program Rules, ensure that their risk management program includes details of how the responsible entity complies with at least one of the following standards and frameworks:
  - The Australian Cyber Security Centre's Essential Eight Maturity Model at maturity level one.
  - AS ISO/IEC 27001:2015.
  - The National Institute of Standards and Technology (**NIST**) Cybersecurity Framework.
  - The Cybersecurity Capability Maturity Model (**C2M2**) at MIL-1.
  - Security Profile 1 of the AESCSF.
  - An equivalent standard.

Based on other electricity utilities' plans and its own discussions with the AER and the NT government, and cognisant of recent cyber security attacks on Australian telecommunications, electricity retail, and health sectors, we consider that achieving and sustaining SP-2 under the AESCSF as quickly as practicable is prudent.[8]

As shown in Figure 1, this implies that Power and Water has to embed 200 practices and anti-patterns, an extra 112 above the practices and anti-patterns to be established to achieve SP-1 (required by June 2024).

The target cyber security maturity level of SP-2 is expected to be achieved by June 2028 (i.e. five years after commencement of the Rules under the enhanced obligations, which at the time of preparing our submission is assumed to be 1 January 2023).

As recommended in the AESCSF, we will prioritise delivery of the 'Priority Set' practices for SP-1 and SP-2 For prudence and efficiency, we intend, where practical, to limit practices to the specific assets and services required under the legislation or to meet foreseeable, material and/or emergent risks. Other frameworks and standards that offer guidance on *how* to implement these elements will also be used and aligned to AESCSF.

1.2 Options analysis

In addressing the new requirements, we considered three options:

1. Blended resourcing model (recommended option).
2. Internal resourcing model.
3. Fully out-sourced model.

These are discussed in the following sections.

1.2.1 Option 1: Blended resourcing model (recommended option)

Under this option we would invest to meet SOCI obligations, demonstrate SP-2 compliance, and address known and emergent risks. This option includes prudent selection of technology, process and information-based initiatives to enable us to improve priority capabilities efficiently and incrementally (and in groups/phases) on a risk-prioritised basis.

The estimated cost of this option overall (i.e. not just the next regulatory period) is $31.4 million (totex) across ICT and OT. Of this $12.9 million is opex, and $18.4 million is capex.

This is the recommended option, as it is the only viable option which:

- Affords the flexibility to address the reality of emergent risks.
- Addresses the resourcing challenges in the Territory.
- Provides certainty and manageability of delivery.

This option ensures coverage of IT and OT to incrementally establish, operate, mature and sustain SP-2 compliant levels of performance.

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8 In accordance with the AESCSF principles, we have an overall AESCSF maturity level of 0.67 as of late 2021. Ongoing cyber security maturity improvement is currently occurring through replacing/upgrading hardware and software that bring more robust cyber resilience (i.e. with the upgrade). We have satisfied the requirements of the ACSC's 'Essential Eight base requirements' in 2021 for our corporate and end user security (**ICT**). However, we independently assessed our OT areas as further behind in maturity.

1.2.2 Option 2: Internal resourcing model

Under this option we would use internal labour and existing technologies to incrementally address capability, process and information gaps required to meet SP2.

Our experience is that we are often unable to attract/compensate suitable in-house people in the Territory, and in particular in specialist fields. This would mean it is unlikely that we would be able to ramp up and keep enough people to provide the necessary capacity and capability to deliver the work efficiently and successfully in the required time.

The estimated cost of this option overall (i.e. not just the next regulatory period) is around $22 million (totex) across ICT and OT. Of this around $18 million is opex and $4 million is capex.

This option is not recommended due to the delivery risk (capabilities of current platforms and capacity of resources). We do not expect this option would allow us to deliver the required program of initiatives to achieve SP-2 by January 2028.

1.2.3 Option 3: Fully out-sourced model

Under this option we would out-source operational elements whilst maintaining in-sourced governance across the processes. This would require heavy use of security services, with positive vetting of compliance by internal resources.

The estimated cost of this option overall (i.e. not just the next regulatory period) is around $40 million (totex) across ICT and OT. Of this around $23 million is opex and $17 million is capex.

This option is not recommended as the cost is significantly higher than a hybrid option. Moreover, an out-sourced model would not provide the internal capability and capacity uplift to adequately govern and manage services of this scale and nature in an efficient manner, and would not provide the level of visibility, control, or responsiveness required.

1.3 Step change forecast

We have started on a path to increase our cyber security resilience in line with our obligations. However, the move to adopt SP-2 will increase our requirements significantly. Our forecast opex trend growth is negative, which means we will not be able to accommodate the additional cyber security expenditure necessary to get to SP-2 without an opex step change.

As a result, we forecast an annual average increase of $0.9 million in SCS opex[9] is necessary to meet minimum compliance requirements to achieve SP-2 by January 2028.

A significant proportion of the incremental opex is to build the internal capability of the cyber security team and to build on existing service agreements for external expertise (e.g. for undertaking cyber security exercises and undertaking vulnerability assessments). Additional resources will be outposted to the OT area and added to the existing IT team progressively from 2024/25.[10]

9 Noting there is a significant associated capital project, and costs are allocated in accordance with the CAM between SCS and ACS.

10 The working assumption is that additional internal resources will be appointed progressively to help sustain the SP-1 and SP-2 practices to reduce reliance on external resources.

The cost profile is relatively flat over the period. The activities necessary to comply with the new obligations are similar, and of a similar magnitude to those required to fulfill our SP-2 obligations on an ongoing basis. The only exception is 2024/25 when, for sequencing purposes, some systems will not yet be initiated.

The costs associated with our uplift in cyber security is shown in Table 1.1.

Table 1.1: Cyber security step change ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Total step change	1.5	1.9	1.9	1.9	1.9	**9.0**
Allocation to SCS	0.7	0.9	0.9	0.9	0.9	**4.4**

The cost estimates were derived from a combination of vendor, consultant, and subject matter expert advice based on a detailed gap analysis.

More information on this program of work (capex and opex) is provided in the Business Case: Cyber Security baseline (see Attachment 8.72).

2. Regulatory obligations

Since moving to the NT NER in 2019, we have begun to build our business capabilities to manage our suite of regulatory obligations. However, we do not yet have the resources or expertise to fulfill all these obligations (e.g. undertaking regulatory investment tests) and are conscious that new obligations are likely to emerge (such as rule development) that we are not yet equipped to manage.

We therefore require an increase in recurrent operating expenditure to be able to fully resource our regulatory obligations and ensure the business can meet its compliance requirements.

2.1 Why a step change is required

We remain early in our journey towards regulatory maturity. We have a number of NT-specific obligations that we must comply with, as well as our obligations under the NT NER. While we have begun establishing the necessary resources and processes necessary to meet all our regulatory requirements, we are not quite there yet. For example, recent audits of our compliance capabilities have identified that we need to make improvements in metering, ring-fencing and connections.[11]

We are also conscious that our business and regulatory personnel have not yet been exposed to the full suite of obligations, such as preparing Regulatory Investment Test (**RIT**) submissions under the NT NER, and participating in rule changes and technical rules developments. These will be new activities for our business, and need to be resourced appropriately.

We therefore require an opex step change in the next regulatory period to:

- Build new systems and capability to manage compliance to our suite of regulatory obligations, and to implement these changes in the operations of our business.
- Understand and prepare for changes including those that were originally subject to a jurisdictional derogation and which will apply in the next period in accordance with the modification instruments.[12]
- Having looked at existing regulatory obligations and forthcoming regulatory changes, we require sufficient resources to allow us to:
  - Participate in the development of the evolution of the NT NER from a policy and rule development perspective. As the only network service provider regulated under the NT NER, we will be expected to provide insight and expert input on rule changes and policy debates relevant to the NT system. We do not currently have the resources to keep across the frequency and scope of rule and guideline changes, or to participate in rule change processes. Our accurate understanding and timeliness of the assessment of proposed changes to the NER is particularly critical as, without actively opting-out, they will automatically apply to the NT NER.

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11 For example, in 2020 after submitting its first ring-fencing compliance report Power and Water received an adverse finding from the independent assurance auditors (Deloitte) of its compliance with its ring-fencing obligations. While we have achieved a significant uplift in compliance with ring-fencing (recently we received a qualified assurance) there are still a number of areas where we have exceptions to our compliance and which Power and Water is still working through internally and with the AER.

12 *National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016*

- Comply with several requirements under the NT NER and related jurisdictional instruments that will apply in the next regulatory period, in particular:
  - **Maintaining Network Technical Code (NTC)**[13] - It was initially envisaged that during the current regulatory period the NT Government would announce the adoption of technical schedules contained in Chapter 5 and 5A with some modifications. This has not occurred and does not look likely to occur. Consequently, there is a growing need to review the network technical code (which is now formally classified under the Framework and Approach as a standard control service) more frequently than under previous jurisdictional arrangements, in order to ensure continual alignment with AEMC rule changes.
  - **Application of RIT-T/ D including stakeholder engagement** – The RIT-T/D mechanism has applied to transmission and distribution investment from 1 July 2020. However, we have not yet needed to undertake a RIT-T/D. As a result, the costs for resourcing and developing these comprehensive submissions have not yet been incurred, nor have the necessary resources to deliver them been established in our business (and therefore do not feature in our base year costs). Given a number of contingent projects are earmarked for the next regulatory period, with more likely in the future as the energy system continues to evolve, the development of RIT-T/Ds will become commonplace over the coming years. We therefore require an opex uplift to be able to resource this.

We consider that these requirements are more efficiently dealt with as a single step change, to capture the efficiencies associated with management compliance across the organisation and reflected in the cost build up method applied for derivation of the forecast.

We note and have taken account of AER's Guidelines, which require consideration that historical increases in the regulatory burden of distributors may be already inherent in productivity growth parameters.[14] However, this is not the case for us. Not only are we new to regulatory oversight under the NT NER, but our forecast opex trend growth is negative meaning trend growth alone will not provide us the ability to reasonably cover our costs.

Each of the cost drivers are described in more detail in the following sections.

2.1.1 Transition to the NT NER is continuing

The Department of Treasury and Finance (**DTF**) on behalf of the NT Government (**NTG**) commenced a progressive adoption of the National Electricity Law and Rules from 1 July 2016, as provided for under the *National Electricity (Northern Territory) (National Uniform Legislation) Act*. This included exemptions from the NT NER as necessary to ensure the costs do not outweigh the benefits over the longer term.

Mature, well-established distribution network service providers (**DNSPs**) in other jurisdictions have operated under the NER for many years and have been able to respond gradually as it has evolved. However, the current framework represented a significant change for us when introduced, and since continued to evolve.

Our 'Transition to the NER' project currently underway, has established an improved assessment of the compliance obligations, and whilst it has resulted in improvements in some areas, it has not been sufficient

13 The NTC is prepared pursuant to the Northern Territory Electricity Reform (Administration) Regulations, as in force at 1 July 2019, which require Power and Water as a network provider to publish a NTC.

14 AER expenditure forecast assessment guideline (*August 2022*), page 26

to ensure compliance to a suitable risk profile. Our initial assumption that we could achieve compliance with our NT NER obligations by 2019 was optimistic. This is particularly in respect to metering, ringfencing and connections. The complexity of how the NER applies in the Territory has added additional costs and delays in achieving compliance. This has been compounded by the significant amount of change in our business structure and ICT systems.

As a result of recent reviews undertaken internally, as well as the Utilities Commission and the AER, we have identified several areas where improvement to compliance is required.

Examples include:

- In 2020 after submitting its first ringfencing compliance report we received an adverse finding from the independent assurance auditors (Deloitte). This prompted us to consider and commit to a number of activities designed to address material gaps over time.[15] While we have achieved a significant uplift in compliance with our ringfencing compliance, with a qualified assurance, there are still a number of areas of non-compliance we are working through internally, and with the AER.[16]
- An independent audit of the *Electricity industry Performance (***EIP***) Code* for 2019/20[17] included nine material breaches relating to indicators for the Guaranteed Service Level scheme, distribution network reliability and network customer service, and a further 22 non-material breaches. This was indicative of the state of our systems and manual processes for reporting and calculating some performance indicators and which continue to provide challenges to meeting the requirements of the EIP Code. Whilst many of the recommendations have now been acquitted, there are still some that remain outstanding as they are dependent on ICT uplifts.

We expect further examples are likely to be identified as this discovery process continues.

2.1.2 Complexity of the application of regulatory frameworks to the NT

A review by Farrier Swier in April 2022,[18] to reflect changes to the NER compliance register[19] into the NT has highlighted the complexity of the current framework, and the need for new systems and capability to be established. The NT NER is unique and complex for the following reasons:

1. **The applicable rules are difficult to find.** It is a principle of good law and regulatory design that laws are readily accessible and understandable by those they affect.[20] This is not the case for the NT NER. The Australian Energy Market Commission's (**AEMC's**) published version of the NT NER cannot simply be read and accepted, without a painstaking check through notes in the published NT NER themselves, the NT's primary legislation and modifying regulations. Only by completing this complex legal task can we (and the AER) understand which rules do or do not apply, to which entities, and at which points in

15 Deloitte. NT NER Compliance Management Framework| PWC Ring-fencing. 27 September 2021.

16 It should be highlighted, there are further challenges associated with implementing ringfencing requirements. Compliance with some of the obligation would result in an inefficient use of resources, such physical separation and staff sharing). Compliance would be costly and difficult, and we consider it would not deliver any customer benefits. This has resulted in submission of a waiver application for specific clauses in the ringfencing guideline, and which was granted in 2022.

17 Utilities Commission, Annual Compliance Report 2020-21, November 2021, page 7.

18 Farrier Swier. Report on the NT NER compliance obligations register. 28 April 2022.

19 Relating to obligations under the National Electricity (NT) Rules (NT NER) arising from AEMC rule changes.

20 See for example the principles for clearer laws at https://www.ag.gov.au/legal-system/access-justice/reducing-complexity-legislation, which include that legislation should enable those affected to understand how the law applies to them.

time.[21] The same challenges apply to understanding the impact of proposed rule changes, and their interaction with other NT regulatory instruments.

2. **There are inaccuracies in published rules.** Some NER amendments appear to have been adopted in the NT NER either unintentionally,[22] or without clarity on their suitability for the NT context with the multiple and different roles of Power and Water. For example, recent modifications to extend derogations for clause 7A.8 made in December 2021 have not been picked up and flowed through into the NT NER.

The Farrier Swier review observed that:

> *It is a difficult legal and technical task for anyone to understand how AEMC rule changes flow through into the NT NER and impact on Power and Water's existing obligations.*
>
> *It is not clear what avenues Power and Water has for highlighting issues and concerns with proposed amendments that may affect the NT electricity market. Currently, the national rule change framework assumes NT NER alignment with the NER without adequately testing feasibility, costs and benefits for the NT. NT specific issues are not addressed succinctly, rather such issues are bundled with all issues raised across the interconnected NEM and are therefore likely to be overlooked as a result.*

As highlighted above, determining which of the NT NER obligations affect our business, and how those rules interact with jurisdictional instruments is a difficult, time consuming and complex task. In addition, each proposed change to the NER is automatically applied to the NT NER unless we opt-out.[23] This requires us to understand and assess each national rule change to determine the feasibility and potential impacts for the Territory, our business and for any related jurisdictional instruments.

This is further complicated by parallel and overlapping reforms at a jurisdictional level to establish a NT Electricity Market and the fact that the underlying assumption of most rule changes and changes to AER Guidelines assumes that networks are part of the NEM and subject to AEMO oversight, which is not the case in the NT. The AEMC has noted in recent rule changes relating to system strength that the changes introduced will be complex in the Territory due the nature of the NT system and to its jurisdictional arrangements, and will likely require further modification.

As the only network service provider regulated under the NT NER, we need to invest a significant amount of time and effort to participate in the development of the evolution of the NT NER from a policy and rule development perspective. We do not currently have the resources to keep across the frequency and scope of rule and guideline changes, or to participate in rule change processes.

During the current period, the frequency and impact of market reforms and AEMC rule changes was not adequately taken into account. Since joining the NT NER, there have been numerous rule changes largely driven by the transition to renewables and challenges posed by the connection of new and disruptive technology. We have been in regular discussions with NT Government concerning the pace of changes

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21 See Farrier Swier. Report on the NT NER compliance obligations register. 28 April 2022. Appendix A. The complexity is highlighted by the fact that, despite its resources and expertise, the AEMC's published NT NER V87 contains errors and omissions when compared with the source NT instruments (e.g. an incorrect published date for 'transitional period' in clause 11A.5).

22 For example, the National Electricity Amendment (Integrated System Planning) Rule 2020

23 This is something that both the NT Government and AEMC have acknowledged in discussions as being problematic and not manageable. The process does not currently include a rule change process or similar for review of implications to the jurisdictional arrangements or the role of the modification regulations.

being experienced in the NT NER, and the lack of resources able to identify potential issues with the drafting of the respective regulatory instruments.

The current backlog means that NT Government is raising issues for consultation with us at least 12 months after relevant rule changes have been made by the AEMC, and therefore which are considered to apply in the Territory. The pace of change means this will only get worse.

2.1.3 Recent changes to our obligations

We have identified requirements that will apply during the next regulatory period, and which we have not undertaken during the current regulatory period. Accordingly, we did not incur expenditure relating to compliance with those requirements in our base year as identified in Table 2.1.

Table 2.1: Additional compliance requirements

Compliance requirement	Elaboration of need
Maintaining Network Technical Code	Maintaining the NTC is explicitly classified as a Standard Control Service in Appendix C of the AER's Framework and Approach Paper dated July 2022 that applies to Power and Water for the period beginning 1 July 2022. The NTC is prepared pursuant to the Northern Territory Electricity Reform (Administration) Regulations, as in force at 1 July 2019, which require Power and Water as a network provider to publish a NTC. Network Technical Code Regulation 25(4) of the *Electricity Reform (Administration) Regulations* states that the NTC must cover the requirements set out in Schedule 2, other than: (a) matters dealt with in the NT NER or (b) matters appropriately dealt with in the System Control Technical Code. Figure 1 sets out the matters listed in Schedule 2, together with their location in this Code or other instrument.
Application of RIT-T/ D including stakeholder engagement	This is a new obligation / test for our regulated investment that apply to transmission and distribution investment effective from 1 July 2020 Under clause 11A.1 of the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016 the RIT-T and RIT-D NT NER obligations did not apply until 1 July 2020. As a new obligation, Power and Water has not incurred expenditure to for additional internal resources, and the upskilling of existing internal resources, in addition to engagement of external technical consultants

It was initially envisaged that during the current regulatory period the NT Government would announce the adoption of technical schedules contained in Chapter 5 and 5A with some modifications. This has not occurred and does not look likely to occur. Consequently, there is a growing need to review the NTC (which is now formally classified under the Framework and Approach as a Standard Control Service) on a more frequent basis than what was previously undertaken under previous jurisdictional arrangements, in order to ensure continual alignment with AEMC rule changes. The NTC has not been compressively reviewed since the NT NER commenced. There have been numerous changes which have occurred in the later part of the current determination period which have, among other things, sought to support the significant uptake of renewables across Australia (such as system strength implications).

We consider that this requires professional support services to conduct comprehensive reviews of NTC (at least two reviews). The cost of these activities is not currently captured in our base year. We have based the expected cost on implementing the Generator Performance Standards (**GPS**) to review and consult on changes to the network technical control code to reflect AEMC rule changes.

We have not had to prepare a RIT-T and RIT-D as clause 11A.1(5) of the modification regulations excludes:

- Projects assessed by the AER for the purposes of its distribution determination for Power and Water under the current regulatory period.
- Projects where an assessment equivalent to a regulatory investment test had been commenced by Power and Water before 1 July 2019.

To date, we have not undertaken any projects outside of these exclusions.

We are required to develop the requirements and new capability to comply with the RIT-T and RIT-D including stakeholder engagement processes, market benefits tests and procurement of non-network solutions. This includes building internal and external capabilities. We will ensure that we develop systems and processes that align with and draw from good practice in other jurisdictions. We will require additional professional services to develop the capability within the Power and Water team.

2.1.4 Our current systems are limited and labour intensive

We are in the midst of implementing significant business and ICT transformation. This will allow us to implement a number of new systems and processes to address the current limitations and help to alleviate the level of manual compliance required to meet our obligations.

Given our limited resources, to-date, we have focussed our efforts on the highest priority items, establishing the requisite systems and processes to demonstrate compliance with these. This has included establishment of a project to manage our pathway to compliance with the NT NER, and more recently to capture compliance requirements and incorporate them into our new ICT systems. Until such time as these systems are fully implemented, there remain a number of manual work-arounds until the system improvements can be made and manual labour intensive processes can be replaced.

We will continue to focus on addressing high risk compliance areas and priorities by first establishing a more robust preventative control landscape, followed by enhancing detective and corrective controls.

2.2 Options analysis

In addressing the new requirements, we considered three options:

1. Status quo.
2. Undertake additional compliance management focussed activities (recommended option).
3. Consider / undertake changes to the regulatory framework.

These are discussed in the following sections.

2.2.1 Option 1: Status quo

This option would involve us not undertaking the additional risk assessment and management activities associated with understanding and managing the regulatory change process. Ultimately this would result in our non-compliance with one or more regulatory obligations.

This option is not recommended as it would also result in risks of poor information, inadequate resources and limitations on our ability to understand and respond to regulatory change.

This option would also be inconsistent with customer and stakeholder expectations regarding the reasonable expectation maintain a safe, secure and reliable network through, amongst other things, compliance with our regulatory obligations.

2.2.2 Option 2: Undertake additional compliance management focussed activities (recommended option)

This option involves undertaking additional operational activities to understand and manage the impacts of regulatory changes in the NT associated with the current regulatory framework and ensure we are able to participate in an informed and timely manner, guiding action on, and responding to emergent issues. This option will see us introduce new compliance systems and processes and which require ongoing opex to use and maintain over the long term.

This option is recommended as it reflects a prudent level of resources to manage compliance related activities. It will allow us to improve the regulatory capability of the organisation to account for newly identified, and reasonably expected upcoming regulatory obligations. It reflects that compliance costs across network businesses are likely to be similar with minimal opportunities for economies of scale across our multi-utility business.

2.2.3 Option 3: Consider / undertake changes to the regulatory framework

Until such time the NT Government considers the costs outweigh the benefits of applying the NT NER, the current framework (as it evolves) will remain, and we are required to comply with it and the AER to enforce it.

Should we pursue this option, we would only be able to influence the manner in which the AER enforces the NT NER. Possibilities could include encouraging the AER to waive or postpone compliance actions.

Ideally, and consistent with the original reform objectives, the NT NER regulatory framework would require AER regulatory decisions that best reflect the NT context, with rules and decisions that value outcomes for Territorians ahead of NEM consistency. However, we understand that the AER has a strong preference for uniformity in rules and their application to regulated entities in all jurisdictions.

This option is not recommended as it assumes changes to the existing regulatory framework (or a waiver from it) which are not within our control, and which are not being pursued by any of the decision-makers.

2.3 Step change forecast

We are currently on a pathway to comply with the NT NER. A minimal level of regulatory compliance expenditure is built into our base year, however, this is insufficient for us to increase our level of regulatory compliance over the next regulatory period. Our trend growth is negative, meaning growth in the amount of expenditure to the extent we need cannot be accommodated without a step change. As a result, we forecast we will need an annual average increase of $1.2 million in opex[24] to comply with our known increase in regulatory obligations.

The costs associated with our uplift in regulatory expertise is shown in Table 2.2.

[24] Noting there is a significant associated capital project, and costs are allocated in accordance with the CAM between SCS and ACS.

Table 2.2: Regulatory obligations step change ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
NT NER regulatory engagement and management	0.5	0.5	0.5	0.5	0.5	**2.6**
Maintaining Network Technical Code	0.3	0.6	0.3	0.6	0.3	**2.1**
Management and coordination of consultation and regulatory investment tests	0.4	0.4	0.4	0.3	0.3	**1.8**
Total step change	**1.2**	**1.5**	**1.2**	**1.4**	**1.1**	**6.6**
Allocation to SCS	**1.1**	**1.4**	**1.1**	**1.3**	**1.0**	**6.0**

The forecast has been developed by a build-up of costs associated with an increase in staffing, and professional support services. We have based this forecast using a combination of methods including:

- Drawing from experience of other DNSPs undertaking similar streams of work.
- Internal estimates of FTEs and professional fees identified.

3. Insurance costs

Increases in aggregate insurance payouts are globally leading to substantial increases in premiums. Our insurance costs have risen 29.9 per cent (in nominal terms) from 2022 to 2023 and we expect will continue to rise over the next regulatory period. An increase in recurrent opex is necessary to cover these externally -driven costs.

3.1 Why a step change is required

Our insurance costs have risen 29.9 per cent from 2022 to 2023. Consistent with other network service providers, we expect to see increases when we look to renew our insurance in 2023 for the next regulatory period.

Insurance costs are increasing across the Australian energy sector. These increases reflect the impact of climate change such as bushfires, floods and other weather events such as cyclones, which have caused increases in aggregate insurance payouts.

In recent regulatory review processes, most network service providers have signalled increases in insurance costs (through the inclusion of a step change or cost pass-through). For example, in its regulatory proposal for the period 2021 to 2026, Powercor initially proposed a $5.0 million (real$2021) step change, together with a cost pass through for future increases. In its Revised Regulatory Proposal it proposed a $28.1 million (real$2021) step change, while also retaining provision for pass through of further increases. After being asked by AER to include a full-period forecast of its expected insurance costs in its proposed opex allowance, it advised an updated step change totalling $67.7 million (real$2021), with an annually-increasing step change profile.[25] Powercor stated it based this increase on a report from its adviser, Marsh.

In its advice to Victorian Power Networks and United Energy, Marsh forecast increases of 20 per cent to 35 per cent in 2022/23, 10 per cent to 20 per cent in 2023/24 and 0 per cent to 10 per cent each year thereafter. While noting the uncertainty, Marsh suggested that those businesses make a minimum allowance at the mid-point of these ranges. [26]

AER engaged Taylor Fry to advise on the insurance cost forecasts of each Victorian business, and AER describes its conclusions from its advisers as follows:

> *The key conclusions from Taylor Fry's report are that the forecasts provided by Marsh are directionally consistent with Taylor Fry's expectations of future premiums, given its understanding of the prevailing market conditions, and can be considered reasonable.*[27]

In a similar instance, with regard to the AER's decision for AusNet Services, AER approved a step change of $45.1 million (real $2021), in line with an updated forecast that AER asked AusNet to provide.[28] The annual profile of this step change reflects the expectations of continuing significant cost increases over the period,

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25 AER Final Decision – Powercor 2021-26, Attachment 6 – Opex. Table 6.11.

26 The advice from Marsh to the Victorian Power Networks and United Energy is contained in Marsh's report dated 23 November 2020, and which is published (in redacted form) on the AER's website (for example from the Powercor determination). We draw attention to the subsection in that report headed *Forecast premiums – expected future costs* (pages 9 and page 10) and in particular the tables on page 10 of that report.

27 AER Final Decision for Powercor – Attachment 6 (opex) (*April 2021*), page 6-37. AER included similar statements in other determinations at this time.

28 AER Final Decision for AusNet Services, Attachment 6, Table 6.9.

as is shown in the table below. Again, AER refers to the same advice from its adviser, Taylor Fry, in its decision.

Table 3.1: Approved insurance cost step change for AusNet Services[29] ($ million, real 2020-21)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Ausnet Services updated revised proposal (as approved by AER)	4.8	6.8	8.9	11.1	13.4	**45.1**

Power and Water's recent insurance premium renewal allocated to SCS was over $2.1 million in 2022/23. This was a significant increase compared to the $1.8 million incurred in 2021/22. As 2021/22 is being used as our base year, we need to reflect this initial uplift, in addition to expected increases in costs over the next regulatory period.

A further relevant factor is that we are scheduled to undertake a market-based asset revaluation in 2023. We expect this will increase valuations of certain assets, which is likely to drive up insurance costs. We have not separately sought to quantify this impact in advance of the revaluation exercise. However, this further underpins the extent of cost increases that we have forecast in our proposed allowance.

We have proposed a rate of increase for insurance costs beyond 2023 that broadly aligns with what we understand to be the basis for the insurance cost increases that were approved for the Victorian DNSPs. Our actual insurance cost increases in 2023 effectively align with the expectation inherent in the Victorian DNSP forecasts and we have no reason to expect our insurance costs will not similarly continue to increase over the next regulatory period.

3.2 Options analysis

In addressing the new requirements, we considered three options:

1. Do nothing / self insurance.
2. Uplift premiums to reflect known 2023 costs, recovering any additional costs incurred in the next period as a pass through.
3. Uplift premiums to reflect known 2023 costs recovering any additional costs as a step change.

These are discussed in the following sections.

3.2.1 Option 1: Do nothing / self-insurance

It is prudent, standard business practice to obtain insurance for events that are insurable at reasonable cost. The cancellation of our insurance policy to rely on self insurance is not consistent with our Risk Management Policy.

It should also be highlighted that, if we decided to not take out insurance, we would need to retain significant additional capital to cover the risks. This would effectively then be self-insuring and an annual cost for this would need to be included in the opex allowance.

[29] AER Final Decision for AusNet Services, April 2021, Attachment 6, Table 6.13

On this basis, we did not consider this to be a viable option, and have not considered it further.

3.2.2 Option 2: Uplift premiums to reflect known 2023 costs, recovering any additional costs incurred in the next period as a pass through

Under this option we would include the known increase in insurance costs for 2022/23 as a step change, and then pass through any additional costs, which are less certain until after we have incurred them, as a cost pass through.

While the magnitude of future cost increases is uncertain and therefore perhaps more appropriately recovered under the cost pass through mechanism, the AER has stated its preference for insurance costs to be forecast as a step change.[30] This is based on its view that where practicable costs should be included as part of the regulatory incentive framework.

We acknowledge the AER's position on this, and that there are decisions inherent in obtaining future cover that Power and Water can manage to an extent, including some aspects of the scope of cover and the level of deductibles. Therefore, we do not consider this option is viable.

3.2.3 Option 3: Uplift premiums to reflect known 2023 costs recovering any additional costs as a step change (recommended option)

This option would see us including a step change accounting for the recent known increase in insurance (only to the extent it affects our forecast opex) and increases throughout the next regulatory period.

This is the recommended option as it aligns with the AER's preferred method of recovering increased insurance costs, and allows us to recover the reasonable cost of insuring our network over the next regulatory period.

3.3 Step change forecast

In developing our insurance forecast for 2024-29, we have:

- Used the $1.8 million SCS opex costs incurred in the 2021/22 base year.
- Added the known 2022/23 SCS opex increase of $0.3 million. [31]
- Escalated the resulting $2.1 million of SCS opex using the mid-point estimate Marsh recommended for Victorian DNSPs. This resulted in an increase of 15 per cent in 2023/24 and 5 per cent per annum thereafter.

We are scheduled to undertake a market-based asset revaluation in 2023. This will likely increase the value of certain assets and result in higher insurance costs. We will substitute our forecast for the revaluation figures when available.

The costs associated with our expected increases in insurance are shown in Table 3.2.

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30 We observe that in recent AER determination processes, four of five Victorian DNSPs proposed to pass through increases in insurance costs. However, the AER did not accept the proposals for a cost pass through of the cost increases and asked those DNSPs to include insurance cost forecasts in their regulatory proposals. Accordingly, DNSPs provided updated opex forecasts to AER, including such costs forecasts as step changes, and the AER accepted these DNSPs' updated forecasts in its determinations.

31 Our quoted insurance cost increases for 2022/23 effectively align with the expectation inherent in the Victorian DNSP forecasts.

Table 3.2: Insurance step change ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Total step change	1.8	2.1	2.4	2.8	3.1	12.2
Allocation to SCS	0.7	0.8	1.0	1.1	1.3	4.9

4. Cloud migration

Cloud infrastructure is a subscription based operating cost. While we are not pursuing an enterprise-wide cloud migration strategy, there are products and services for which cloud-based solutions are the only offering by the preferred vendors. A step change is therefore required to implement and maintain a small digital cloud presence for a suite of core ICT systems.

4.1 Why a step change is required

4.1.1 Migration to the cloud is necessary in some instances

Our enterprise-wide ICT strategy does not include migration to cloud-based methodologies. This is because for an organisation of Power and Water's relatively modest scale, isolation, and HR practices,[32] it is likely to be less cost effective for Power and Water to adopt broad cloud-based solutions.

However, an increasing number of software application vendors only offer could-based services. While most of our ICT capabilities are hosted on-premises, there are some instances where a cloud service is the more prudent option (due to the need for ongoing vendor support), or is likely to become the only option in the near future. A step change is therefore necessary to establish a small cloud presence.

4.2 Options analysis

In addressing the new requirements, we considered three options:

1. Do not migrate to the cloud.
2. Vendor-driven migration to the cloud.
3. Proactive migration to the cloud.

These are discussed in the following sections.

4.2.1 Option 1: Do not migrate to the cloud

Option 1 is based on adopting only on-premise methodologies when replacing, upgrading or introducing infrastructure, software, platforms, etc. This option has not been costed.

This approach is not practicable because Power and Water has an ongoing requirement for products from vendors which no longer offer on-premise solutions or are not investing in upgrading and refreshing their on-premise solutions. The alternatives of either retaining out-of-date systems or transitioning to inferior systems offered by other vendors, is not prudent or commercially attractive.

32 Making staff redundant is not a practicable option.

4.2.2 Option 2: Vendor-driven migration to the cloud (recommended option)

Option 2 is based on adopting the following approach:

- On-premise methodologies where available and cost-effective (e.g. replacing/upgrading existing on-premise infrastructure with on-premise infrastructure when the former is at end-of-life).
- Cloud methodologies only where an on-premise solution is not feasible.

This is the preferred option, whereby we only migrate to a digital cloud where necessary and prudent to do so, thus only requiring a small cloud footprint.

4.2.3 Option 3: Proactive migration to the cloud

Option 3 is based on adopting cloud-based solutions when replacing or upgrading all software products or when introducing new infrastructure, applications, platforms, etc. This would likely result in the staged migration to an enterprise-wide digital cloud footprint.

We have not yet identified any situations in which the driver for broad cloud migration is likely to reduce the total cost via a capex to opex trade-off. This is not the recommended approach and has not been costed.

4.3 Step change forecast

The costs associated with our expected transition of some systems to the cloud are shown in Table 4.1.

Table 4.1: Cloud migration step change ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Total step change	1.6	1.6	1.6	1.6	1.6	**8.0**
Allocation to SCS	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**4.0**

The costs for cloud migration are based on vendor quotes and, where applicable, the estimated volume of services required over the period. The costs comprise management, data and application support fees plus licensing and subscription fees.

More information on this step change is provided in the ICT Strategy (see Attachment 8.65).

5. OT capability uplift

The opex step change for OT Capability Uplift covers the increase in vendor support, development and resource costs necessary for the new and upgraded OT systems being introduced as a part of the OT Capability Uplift Project (capex).

5.1 Why a step change is required

5.1.1 The need for investment

Our current suite of OT systems are disparate and obsolete, and considerably short of where a modern distribution network service provider should be. The OT Uplift is required to bring our systems up to industry standard and give us the ability to better manage existing levels of distributed energy resources (**DER**) and renewables.

A significant proportion of our current systems for managing the distribution network are almost completely manual. This creates significant risks through dependencies on key resources, and does not allow for timely network assessments. Our current outage management system (**OMS**) is also obsolete and no longer fit-for-purpose.

The manual nature of our systems is becoming increasingly problematic as the level of DER across our networks grows. DER involves two-way power flows, which can affect power quality and safety. We must therefore, at the very least, introduce industry standard OT such as a Distribution Management System (**DMS**) module.

The OT Capability Uplift project seeks to raise the standard of our systems, making them suitable for operating today's networks, while laying the foundation for future network management systems.

5.1.2 What the OT Capability Uplift project will deliver

The OT Capability Uplift project will provide a single, integrated solution with tools to:

- Remotely monitor and control the network.
- Better manage planned and emergency outages.
- Optimise power-flow management.
- Improve fault location analysis, fault isolation and fault restoration capabilities.

5.2 Options analysis

In addressing the new requirements, we considered four options:

1. Integrated point solutions.
2. New consolidated platform.
3. Upgrade, extend and integrate Energy Management System (**EMS**) platform.
4. Business-as-usual incremental improvements.

These are discussed in the following sections.

5.2.1 Option 1: Integrated point solutions

This option is based on introducing multiple products and multiple vendors. The estimated cost of this option overall (i.e. not just the next regulatory period) is around $45 - $55 million. An opex cost has not been estimated.

Consideration of critical infrastructure legislation makes this option extremely unattractive, due to the amount of configuration and reconfiguration and the overall risk footprint associated with this approach. The option would increase effort, cost and risk compared to the recommended option.

5.2.2 Option 2: New consolidated platform

The scale of effort, risk and cost to introduce a new platform is comparably prohibitive. The estimated cost of this option overall (i.e. not just the next regulatory period) is around $67 - $89 million. An opex cost has not been estimated.

The risk of failing to deliver a completely new platform successfully in parallel with managing the current system is considerable, given the limited capability and capacity of our staff to support the implementation (and which would be necessary regardless of whether an external resource delivery model is adopted). This option is not recommended.

5.2.3 Option 3: Upgrade, extend and integrate EMS platform (recommended option)

This is the recommended option and would achieve an integrated solution that will progressively develop the target state for EMS, DMS, OMS and related/supporting systems and capabilities. The The estimated cost of this option overall (i.e. not just the next regulatory period) is $39.5 million. The SCS opex cost is $18.8 million over the next regulatory period.

5.2.4 Option 4: Business-as-usual incremental improvements

The current network and supporting systems are unable to support the required functionality to cope with the increasing complexity of operating the network with increased penetration of renewable energy in general and DER in particular. The challenges are already evident and with the expected addition of electric vehicle charging and discharging, managing system low and system peak events in normal state operation will be progressively challenging. This option is not recommended as business-as-usual incremental improvements with point capabilities will neither meet the need, nor be deliverable with the existing technologies and data.

5.3 Step change forecast

New functional modules and an information model will be established and much of the project costs will be capex or capitalised opex. However, there will be three types of ongoing opex required to provide ongoing maintenance support and to actually manage and deploy the functionality afforded by the new systems:

- Additional vendor support for the additional hardware and software introduced by the OT capability Uplift project[33]. The cost estimate for this is based on vendor quotes.
- Additional application development support from external consultants. The cost estimate for this is based on a provisional sum provided by an external consultant, and our experience.

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33 Including the upgrades associated directly with the EMS project – subject to a separate business case.

- Additional staff to both manage the network and apply the increased functionality. One component of the cost estimate is an additional three resources – a new control room operator for the low voltage system, a new analyst to make use of the new tools and information provided by the project and to support the control room operators. The second component is a new control room operator to operate the upgraded energy management system. The resource costs are based on the appropriate Power and Water salary bands.

We have liaised with EvoEnergy and Ausgrid during the development of the OT Capability Uplift project. EvoEnergy has successfully implemented a similar scope of work and has emphasised the importance and cost involved in ensuring that data (i.e. network data, live supervisory and control data acquisition (**SCADA**) data, asset data, customer data, connectivity data, geospatial data, etc) is complete and correct. For Power and Water, work will need to be undertaken in the current regulatory period, including field data collection.

The costs associated with our expected uplift in OT capability are shown in Table 5.1.

Table 5.1: OT Capability Uplift step change ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Total step change	4.0	4.0	2.8	4.0	4.0	**18.8**
Allocation to SCS	**4.0**	**4.0**	**2.8**	**4.0**	**4.0**	**18.8**

More information on this program of work (capex and opex) is provided in the Business Case: OT Capacity Uplift (see Attachments 8.73 and 8.74).

6. Future network

The transition of the energy system in the Northern Territory (NT) is being led by our customers at the distribution and transmission connection level. Our customers expect the grid to facilitate greater diversity in supply from variable renewable sources, whilst maintaining safe, reliable and affordable energy systems.

An opex increase is required to ensure that Power and Water is adequately resourced to respond to these requirements, and plan the future of the NT's major electricity network.

6.1 Why a step change is required

6.1.1 The energy transition

Across Australia and worldwide, power systems are decarbonising, making the transition from centrally located fossil fuel thermal generation to large and small scale renewables connected at both the transmission and distribution level. The NT is experiencing this same transition, which requires Power and Water to improve its network planning and analysis capabilities.

Whereas the OT Capability Uplift is about bringing our systems up to today's industry standard, the Future Networks step change is about building the capability and resources to be able to plan and manage the efficient and seamless transition to a renewable energy future.

Several external factors are driving Power and Water's need to manage the energy transition in a more proactive manner:

- **The Darwin-Katherine Electricity System Plan (DKESP)**: In October 2021, the DKESP[34] charted the pathway to decarbonise the Darwin Katherine Interconnected System and outlined how the NT energy system needs to operate in 2030 to maintain reliability and security. Power and Water will have to design its networks and improve its capabilities to support the new technologies that underpin the DKESP. *"This strategic and overarching document will inform the operational decisions of the Power and Water Corporation, Territory Generation and Jacana Energy, ensuring coordinated and effective actions across government in an effort to realise a cleaner, lower cost and secure electricity system."*[35]
- **NT Government's Renewable Energy Target:** The NT Government has set a target to enable 50 per cent of energy produced in the NT to be from renewable sources by 2030[36]. Our networks are central to facilitating this.

There is also a large forward-looking pipeline of large scale renewable connections that require us to provide greater transparency of known network constraints.

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[34] Northern Territory Government, Darwin-Katherine Electricity System Plan, https://territoryrenewableenergy.nt.gov.au/strategies-and-plans/electricity-system-plans#Darwin-Katherine-electricity-system-plan

[35] Northern Territory Government, Darwin-Katherine Electricity System Plan, p5, https://territoryrenewableenergy.nt.gov.au/strategies-and-plans/electricity-system-plans#Darwin-Katherine-electricity-system-plan

[36] Territory Renewable Energy, Our Renewable Energy Target, https://territoryrenewableenergy.nt.gov.au/about/our-renewable-energy-target

This step change only relates to those activities that materially impact opex and which have not been accounted for in our base year costs.

6.1.2 Need for a DOE solution to manage minimum demand

Minimum demand in the Darwin-Katherine system is forecast to fall below the existing 67 MW threshold[37] in 2025-26, potentially reaching 13 MW by 2030-31.[38] This can cause significant system security issues.

The declining minimum demand is caused by the proliferation of rooftop solar, which produces excess electricity during the daytime and displaces the large thermal generation necessary to provide inertia services and maintain system strength. Customers have told us that they value rooftop solar and want to be able to continue to connect it. We therefore need a technical solution that will allow us to manage the minimum demand issue while allowing continued growth in DER.

As discussed in the capex business case (Attachment 8.61), we plan to develop a GridQube Dynamic Operating Envelope (**DOE**) solution. This is a central element of our Future Network Strategy. The DOE solution requires a combination of capex and opex investment during the next RCP. The opex components are identified in the table below.

Table 6.1: Opex components of DOE solution

Requirement	Proposed solution
GridQube requirements for DOE	We will develop a network state estimation capability and extrapolate to unmonitored sections of the LV network to understand and dynamically manage constraints. We will offer customers flexible connections where their export is dynamically calculated for the benefit of increased export capacity.
Implementation and integration of DOEs	IT infrastructure to support Communications of DOEs to customer inverters.
DER Register	In order to improve our LV network visibility, we need to understand the location, type and characteristics of DER assets. We aim to improve our non-public DER Register database to itemise DER assets in the network, including rooftop solar PV, EV Supply Equipment and home batteries. Data cleansing in the current DER register to improve database accuracy.
Compliance	We aim to take a more active role in ensuring DER compliance through accreditation processes and monitoring by supporting the accreditation and compliance process. We can also use improved network visibility to monitor inverter setting compliance such as solar PV output. Power and Water is planning to establish a solar compliance program that monitors solar output using the grid export monitoring to assess inverter settings compliance.

37 *Darwin Katherine System Plan*, Figure 18.

38 See Attachment 8.48.

6.1.3 Increasing complexity associated with connecting renewables

The NT Government's commitment to the 50 per cent renewables target, coupled with a number of large projects already in the pipeline, means the volume of large-scale renewables seeking network connection will grow. It is therefore important that the connection process remains fit for purpose.

During the next regulatory period (and beyond), we need to undertake work to improve and then manage our connection processes for large scale renewables. We will ensure we develop connection arrangements that align with and draw from good practice in other jurisdictions. This work will require additional professional services to develop the capability within the Power and Water team.

The proposed step change requirement excludes managing individual connection applications, which will be recovered directly from applicants.

6.1.4 New demands on the power system

The growing complexity of the power system means we require the ability to assess network operation and electricity flows. This includes dynamic and electromagnetic transience analysis of new and emerging energy technologies and how they interact with our energy system. This capability does not currently exist in our business.

The results of this new network assessment capability will be used to inform system plans with Government, update and modify network protection settings, and inform future operation conditions working alongside NTESMO.

We will also require a number of specific reviews and advice to inform how Power and Water should respond to new operating conditions caused by large batteries, EVs, as well as the effect of climate change, decarbonisation, and related government policy.

6.1.5 Higher demand for stakeholder engagement and change management

We recognise the need to resource a delivery model focused on the needs of our consumers and stakeholders, and to ensure that the systems we develop can be transitioned effectively into the business. Based on the experience of other DNSPs this was a material component of their programs and linked directly to the success of the other initiatives e.g. DOE solution.

In support of the Future Network Strategy, professional support services will be required to develop and facilitate stakeholder engagement and change leadership, building the capability of the Power and Water team.

6.2 Options analysis

In addressing the new requirements, we considered three options:

5. Maintain status quo.
6. Undertake responsible management activities.
7. Undertake DOE investment only.

These are discussed in the following sections.

6.2.1 Option 1: Status quo

This option would involve not undertaking the additional investment in developing our capabilities for the network of the future, and more specifically ensuring that the network meets the required performance standards in response to minimum load.

We consider this option is not feasible because this would lead to Power and Water failing to comply with the requirements of the NT NER, jurisdictional planning standards, and the reform and planning objectives of the NT Government. This outcome would be inconsistent with our customers' expectations regarding the development of the electricity network to deliver consumer value, and would be inconsistent with the direct feedback from stakeholder engagement on the NT's energy transition.

6.2.2 Option 2: Undertake responsible management activities (recommended option)

This option involves undertaking additional operational activities to understand better, measure and manage the impact of increasing renewable generation including roof-top solar PV and large scale renewable generation to the reliability and security of the NT power system. We consider that these activities are necessary to enable us to comply with the current performance standards, particularly the NT NER, jurisdictional planning standards and NT Government policy and reform objectives.

Specifically, under this option, we will deliver the DOE solution alongside customers to mitigate the negative impacts of minimum demand (associated with the uptake of renewables) and enable customers to connect additional rooftop PV.

The proposed opex step change is dependent on the forecast capex for Future Networks initiatives being included in the capex allowance.

6.2.3 Option 3: Undertake DOE investment only

This option would limit the operating expenditure to implementing the DOE solution only. While this option would mitigate the immediate issues associated with minimum demand, it does not address transmission system security and reliability issues. It would also not fully align with the NT government policy and reform agenda.

This option is not consistent with Power and Water's future network strategy. It would also be inconsistent with our customers' expectations regarding the development of the electricity network to deliver consumer value, and would be inconsistent with the direct feedback from stakeholder engagement on the NT's energy transition.

6.3 Step change forecast

The costs associated with our future network are shown in Table 6.2.

Table 6.2: Future network step change components ($ million real 2024)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Increasing complexity associated with connecting renewables	0.7	0.7	1.9	02.0	2.2	**7.4**
DOE solution to management minimum demand	0.7	0.7	0.7	0.7	0.7	**3.7**

	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Network Planning & System Support Services	0.5	0.5	0.5	0.5	0.5	**2.7**
Higher demand for stakeholder engagement and change management	0.6	0.3	0.3	0.3	0.3	**1.8**
Total step change	**2.5**	**2.2**	**3.5**	**3.6**	**3.8**	**15.6**
Allocation to SCS	**2.3**	**2.0**	**3.2**	**3.3**	**3.4**	**14.1**

We have developed this opex step change using a combination of methods including:

- Estimates from external advisors with experience in designing and implementing DOE solutions.
- Drawing from experience of other DNSPs implementing DOE solutions and managing changes to the power system.
- Internal estimates of resourcing costs and professional fees.

The proposed opex step change has been developed by a build-up of costs associated with an increase in staffing, and professional support services.

More information on this program of work (capex and opex) is provided in the Future Network Strategy (Attachment 8.08) and Business Case: Dynamic Operating Envelopes (Attachment 8.61).

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