Attachment 03.2P

PowerWater

SCS and ACS opex step changes

2019-20 to 2023-24

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Contents

1. Summary

Key messages

1. Our proposed Standard Control Service (SCS) and Alternative Control Service (ACS) Metering opex step changes reflect increases in costs due to:
   a. new regulatory obligations as a result of the Northern Territory (NT) Government reforms to transition to the National Electricity (NT) Rules (NT NER); and
   b. our new and replacement smart meter policy position.
2. Our proposed total SCS opex step changes from 1 July 2019 are $1.48 million per annum (real $2018-19).
3. Our total proposed ACS opex step changes in 2019-20 are $0.2 million, decreasing to a negative step change of $0.34 million in 2023-24 (real $2018-19).
4. Development of our proposed step changes has been informed by our customer engagement and research program. In this, we tested our approach to dealing with new obligations, as well as customer preferences for various customer funded initiatives identified in phase one of our engagement program.

Our new regulatory obligations apply from 2019-20. As result, we will incur additional expenditure, and our proposed opex step changes from that date. This means that no amounts are included in the 2016-17 actual costs for these obligations, which form the basis of our base year opex for our regulatory proposal. Nor will any expenditure related to the step changes be included in our 2017-18 costs, which we expect the Australian Energy Regulator (AER) will use as its base year opex in its final determination.

1.1 SCS opex step changes

Table 1-1 below sets out our proposed SCS opex step changes to meet our new regulatory obligations. Attachment 12.6 sets out our calculation of the SCS opex step changes.

Table 1-1 – SCS opex step changes

$M, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
National connections process	0.49	0.49	0.49	0.49	0.49	2.43
Metering compliance type 7	0.02	0.02	0.02	0.02	0.02	0.12
Metering Data Management System (MDMS) commissioning and early processing	0.16	0.16	0.16	0.16	0.16	0.78
Planning resources	0.55	0.55	0.55	0.55	0.55	2.74
Guaranteed service levels (GSLs)	0.27	0.27	0.27	0.27	0.26	1.33
Total SCS	1.48	1.48	1.48	1.48	1.48	7.40

Section 2 provides details on each of these step changes.

1.2 ACS Metering opex step changes

Table 1-2 below sets out our proposed ACS Metering opex step changes to meet our new regulatory obligations under Chapter 7A of the NT NER and to implement our new and replacement smart meter policy position. Attachment 12.6 sets out our calculation of the ACS opex step changes.

Table 1-2 – ACS metering opex step changes

$'000s, Real 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Chapter 7A of the NT NER						
Inspection and testing	312.4	312.4	312.4	312.4	312.4	1,562.1
Metering compliance type 1-6	39.1	39.1	39.1	39.1	39.1	195.7
Southern Region metering technicians	312.4	312.4	312.4	312.4	312.4	1,562.1
New and Replacement Meter Policy						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	200.1	66.5	-72.3	-207.2	-335.9	-348.8

Section 3 provides details on each of these step changes.

1.3 Customer engagement and research on step change[redacted]

1.3.1 Regulatory baseline

The step changes presented in this paper only reflect known new regulatory obligations.

Because there remains some uncertainty about further new obligations which come into effect during 2019-24, we needed to develop an approach to dealing with uncertainty when forecasting our 2019-24 costs. We consulted our Customer Advisory Council (CAC) when doing so, and we call our resulting approach our regulatory baseline.

We presented to our third council meeting why we need to define a regulatory baseline for the 2019-24 regulatory determination process and discussed options for dealing with cost uncertainty. We discussed our preferred approach of excluding uncertain items and focussing on what we know with sufficient certainty to forecast the costs accurately. This approach means we only recover costs of our known regulatory obligations and avoid charging prices that incorporate the costs of regulatory changes that might not occur. As new obligations become known, a pass through would be sought from the AER.

The CAC discussed these plans and their consequences for customers, agreeing that the conservative approach in our regulatory baseline struck the right balance of risk for customer and users and avoided inflating 2019-24 prices amid uncertainty. The step changes identified herein, reflect this approach.

1.3.2 Customer funded initiatives

Our step change forecasts do not include forecasts for discretionary customer-funded initiatives, as a direct result of our customer research on willingness to pay for these. Our phase one research identified strong interest in further exploring an in-home energy audit program and a significant ongoing customer engagement program. Our phase two deliberative forums were presented options and cost per customer impacts of these and there was very little support. Consequently, we are not proposing a step change for either of these activities and will fund our 2019-24 engagement program by realising cost efficiencies from elsewhere in our business-as-usual cost base.

2. SCS opex step changes

This section sets out our proposed SCS opex step changes comprising:

- National connections process
- Metering compliance Type 7
- MDMS commissioning and early processing
- Planning resources
- Guaranteed Service Level (GSL) payments.

National connections process

1. Description
Compliance with increased administration requirements related to national connections, created by the introduction of Chapter 5A of the NT NER.
2. Driver of the step change - compliance
From 1 July 2019, Chapter 5A of the NT NER will apply in the NT. Chapter 5A prescribes the process to be followed for the provision of connection services. We provide connection services following a request from a customer either to make a new connection to the distribution network or alter an existing connection to the distribution network. The provisions of Chapter 5A of the NT NER are more onerous than those contained in the NT's *Electricity Networks (Third Party Access) Act* and related instruments that cover connections in the jurisdictional framework.
3. Strategic alignment
The step change is required under our compliance policy, which is a fundamental part of our governance. Unless the step change is included, our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting regulatory obligations.
4. Options considered
• Option 1. Do nothing. Retain current approach to providing connection services. • Option 2. Create new systems and processes from first principles and a new business group to administer them. • Option 3. Adapt existing systems and processes to obtain least-cost compliance with regulatory obligations.

5. Preferred option

Option 1 is not viable. While it is the least cost option:

- it would not provide the customer protections contained in Chapter 5A; and
- it would result in ongoing non-compliances with the NT NER and therefore our network licence issued by the Utilities Commission (UC).

Option 2 would provide:

- the customer protections contained in Chapter 5A of the NT NER;
- a refined, sophisticated process to provide a state-of-the-art customer experience; and
- compliance with regulatory obligations.

However, Option 2 would be an expensive solution that does not leverage existing capability.

Option 3 is the preferred option. It would provide the benefits of Option 2, albeit with a less refined delivery of services, at a much lower incremental cost as it involves amendments to existing processes and systems. The disruption to service delivery should be minimised, compared with option 2.

6. Expenditure forecasting method

The forecast was created by calculating the incremental cost of four full time equivalents (FTEs) required to carry out the new functions and administration requirements of Chapter 5A.

The first year of expenditure is 2019-20, the first year of the regulatory obligation. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.

Costs associated with setting up systems to accommodate the changed regulatory obligations fall before the start of the current regulatory period.

7. Expenditure forecasting assumptions
Process and system changes to accommodate the new compliance obligations must be completed before the start of the next regulatory period; the associated costs (which are capital in nature) fall outside of the scope of this step change. The main assumptions are: • it will take four extra staff (three admin and one engineer) to accommodate more onerous requirements of Chapter 5A; • labour rates ($60.17/hour for admin and $107.40/hour for engineering) and hours over the year (1,638 for admin and 1,664 for engineering) reflect the 2017-18 budgeted personnel costs and inclusive of salary on-costs[1]; and • total forecast for four staff = (1,638 * 3 * $60.17) + ($107.40 * 1,664) = $474,389 (2017-18$). Refer to Chapter 4 of the regulatory proposal for more detail on the new obligations.
8. Step change benefits
The step change will provide the following benefits: • improved customer connection process; and • enable us to comply with our regulatory obligations.
9. Classification of cost
The costs will be classified as network overheads.

Metering compliance type 7

1. Description
Prepare and maintain a five-year rolling sampling plan for type 7 metering installations for the Northern and Southern Regions and assess against that plan.
2. Driver of the step change - compliance
Compliance is required with the obligations imposed by Chapter 7A of the NT NER regarding type 7 metering installations. One task is to prepare and maintain a five-year rolling sampling plan for type 7 metering installations for the Northern and Southern Regions. The obligation to verify, substitute and/or estimate type 7 metering data is detailed in Schedule 7A.3 of Chapter 7A of the NT NER: Schedules 7A.3.7 & 7A.3.13. We must also assess our compliance of the type 7 metering installations in accordance with that plan.

[1] As set out in Attachment 3.3 an internal memo '2017-18 Labour recovery rates', 30 June 2017.

3. Strategic alignment
This step change aligns with our compliance policy and the Corporate vision, and is necessary to meet our regulatory obligations and requirements. Our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations unless the step change is included.
4. Options considered
• Option 1. Internal Metering Service personnel. • Option 2. Outsourced to Power and Water internal audit personnel. • Option 3. Outsourced to external consultants.
5. Preferred option
The preferred option is to appoint and utilise a Metering Service internal resource (option 1). This is preferred because an understanding of the technical culture would be beneficial in determining findings and forming views on recommendations.
6. Expenditure forecasting method
The forecast was created by calculating the incremental cost of the new obligation. The first year of expenditure is 2019-20, the first year of the regulatory obligation. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.
7. Expenditure forecasting assumptions
The utilisation of a person to perform this task is estimated to be 1 week per year. Another task is to assess compliance of the type 7 metering installations in accordance with that plan. The utilisation of a person to perform this task is estimated to be 6 weeks per year (3 weeks Northern Region site visits; 2 weeks Southern Region site visits and 1 week for a report). If the same person was to perform both tasks, the duration would be 7 weeks per year. The forecast expenditure on the internal resource is costed as follows: • available hours of 1 person = 263 (7 weeks, or 0.16 FTE); • hourly wage rate of meter technician with audit skills = $91.59[2](2017-18 budgeted personnel costs and inclusive of salary on-costs); and • total annual expenditure = $24,088 (1 x 263 x $91.59) (2017-18$).

[2] Ibid.

8. Step change benefits
Benefits arise as follows: • we will be able to meet our Electricity Network Licence requirements for billing and the requirements of Chapter 7A.
9. Classification of cost
The costs will be classified as routine maintenance.

MDMS commissioning and early processing

1. Description
Operation of the MDMS is required to comply with the verification, substitution and estimation obligations imposed by Chapter 7A. These functions are required by us to deliver our SCS including our billing functions.
2. Driver of the step change - compliance
The MDMS is required to comply with the verification, substitution and estimation obligations imposed by Schedule 7A.3 of Chapter 7A of the NT NER. This requires us to install, commission and operate a new processing tool (MDMS) once the metering data is remotely collected (by another tool). This tool checks the integrity of the collected data and, where necessary, makes substitutions in accordance with predetermined rules or otherwise requires a manual estimation of the data to be undertaken by a skilled operator. Currently, our Metering Services team does not have a similar system – this is not a replacement system.
3. Strategic alignment
This step change aligns with our compliance policy and Corporate vision (it is specifically identified in the 2017-18 Statement of Corporate Intent) and is necessary to meet our regulatory obligations and requirements. Our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover its efficient cost in meeting our regulatory obligations unless the step change is included.
4. Options considered
• Option 1. Internal Metering Services personnel. • Option 2. Power and Water corporate information and communication technology (ICT) resource who has capability to manage the operation and reporting requirements of the MDMS.

5. Preferred option

The preferred option is to appoint and utilise an internal Metering Services resource fully assigned to managing the operation of the MDMS (option 1). This is because of the need to have:

- metering skills to investigate any errors detected in the validation and substitution process;
- metering skills to estimate power consumption quantities (and possibly power production quantities) where metering failures have occurred; and
- a suitably skilled person to closely integrate the daily operation of the MDMS with the corporate ICT services and the corporate billing services (Customer Service Centre).

6. Expenditure forecasting method

The forecast was created by calculating the incremental cost of the new obligation. The first year of expenditure is 2019-20. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.

7. Expenditure forecasting assumptions

The forecast expenditure on the internal resource is costed as follows:

- available hours of 1 person = 1,668 (2017-18 budgeted personnel[3] costs and inclusive of salary on-costs);
- hourly wage rate of data technician = $91.59 (2017-18 budgeted personnel[4] costs and inclusive of salary on-costs);
- total annual expenditure = $152,772 (1 x 1,668 x $91.59) (2017-18$); and
- it is assumed that the appointed person would be recruited prior to 1 July 2019.

8. Step change benefits

Benefits arise as follows:

- we will be able to meet our requirements for network billing and the regulatory accuracy requirements of the National Measurement Act (as expressed through Chapter 7A of the NT NER).

9. Classification of cost

The costs will be classified as network overheads.

[3] Ibid.

[4] Ibid.

Planning resources

1. Description
Increased planning functions created for the introduction of the NT NER.
2. Driver of the step change – compliance
With the move to the national electricity framework, more work is required in network planning to comply with the NT NER and to meet the expectations of the AER on what constitutes 'best practice' asset management practices. This requires a maturing of our planning function, which is currently small and relies on external support to manage peak requirements.
3. Strategic alignment
The step change is required under our compliance policy, which is a fundamental part of our governance. Unless the step change is included, our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations.
4. Options considered
• Option 1. Outsource. • Option 2. Appoint internal engineering staff.
5. Preferred option
The preferred option is to appoint and utilise internal resources fully assigned to the planning function (option 2). This will provide us with in-house expertise that will assist in managing our asset base consistent with what a prudent operator would do.
6. Expenditure forecasting method
The forecast was created by calculating the incremental cost of three FTEs required to carry out the new functions and administration requirements. The first year of expenditure is 2019-20. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.

7. Expenditure forecasting assumptions
The main assumptions are: • it will take 3 extra engineering staff; • labour rates are $107.40/hour and 1,664 hours over the year reflecting the 2017-18 budgeted personnel costs and inclusive of salary on-costs [5]; and • total forecast for three staff = 1,664 * 3 * $107.40, or $536,141 (2017-18$).
8. Step change benefits
The step change will provide the following benefits: • improved planning and asset management practices; and • enable us to comply with our regulatory obligations.
9. Classification of cost
The costs will be classified as network overheads.

Guaranteed Service Level (GSL) payments

1. Description
Additional opex to accommodate increased GSL payments resulting from the new jurisdictional Electricity Industry Performance Code (the EIP Code), which replaces the Electricity Standards of Service Code and the Guaranteed Service Level Code.
2. Driver of the step change - compliance
The jurisdictional regulator, the UC, undertook a review of the existing codes. The new EIP Code and Feeder Category Guidelines, were published by the UC on 25 October 2017 and commenced on that day. Under the new code, from 2019-20 onwards, a revised GSL scheme will operate which: • increases the values of the payments to be made to customers when thresholds are exceeded; and • removes the distinction between urban and rural areas in respect of GSL thresholds.
3. Strategic alignment
This step change aligns with our compliance policy and Corporate vision and is necessary to meet our regulatory obligations and requirements. Our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations unless the step change is included.

[5] Ibid.

4. Options considered

- Option 1. Do nothing.
- Option 2. Compliance without passing increased costs on to customers.
- Option 3. Compliance, passing increased costs on to customers.

5. Preferred option

Option 1 is not viable. A GSL scheme is part of the regulatory customer protection regime. We, as a customer-centric business, need to implement this scheme to promote continuous improvement in customer service provision.

Option 2 results in the incremental GSL liability being absorbed by us and not achieving the objectives in clause 6.5.6(c) of the NT NER. This is not consistent with the intent of the regulatory regime.

Option 3 is the preferred option. The efficient funding of GSL liability through regulatory revenues is a central part of the service incentive regime. Further, in revising the GSL scheme, the UC considered the impact of the revised thresholds and payment values upon both us and our customer base (see the EIP code) and determined that the cost would not be material and not exceed the benefits from the stricter scheme. Consequently, we consider that recovering from customers the efficient cost of meeting the obligations in the GSL scheme is the best option.

6. Expenditure forecasting method

The magnitude of the GSL step change was calculated by:

- calculating the average GSL performance measures from 2014-15 to 2016-17 (data for earlier years was not available); and
- estimating the annual GSL liability by applying the new annual charges to the average GSL performance measures.

The first year of expenditure is 2019-20 and is estimated at $267,846 decreasing to $264,852 in 2023-24 ($2017-18).

Note that we have removed from our base year opex the expenditure incurred under the current GSL scheme.

7. Expenditure forecasting assumptions

Assumptions:

- future distribution network reliability will be similar to past distribution network reliability; and
- we will have sufficient revenue to support a maintenance and replacement program to ensure distribution reliability remains relatively unchanged.

8. Step change benefits
The step change will provide the following benefits: • enable us to recover our efficient costs of complying with our regulatory obligations.
9. Classification of cost
The costs will be classified as network overheads.

3. ACS Metering step changes

This section sets out our proposed ACS opex step changes comprising:

- Chapter 7A of the NT NER:
  - Inspection and testing
  - Metering compliance type 1- 6
  - Southern Region metering technicians.
- New and Replacement Meter Policy

[redacted]

Inspection and testing

1. Description
Compliance with new inspection and testing requirements.
2. Driver of the step change - compliance
We must comply with the inspection and test requirements of Schedule 7A.2 ‘Inspection and testing requirements’ (Tables S7A.2.1.2 & S7A.2.1.3) in Chapter 7A of the NT NER. In the current regulatory period, there is no compliance obligation. The current regulatory Metering Code simply states: “Testing of a revenue metering installation shall be carried out in accordance with the Network Operator’s metering manuals”. The meter manual states in section 5.6 on In-Service Testing: “Inspection, testing, or maintenance of metering installations may be carried out by Power and Water technicians at any time.” That is, there are no guidelines on timing obligations. Nor is there a timing obligation on routine inspection of metering installations. Chapter 7A represents a material increase in our testing and inspection obligations.
3. Strategic alignment
This step change aligns with our compliance policy and the Corporate vision and is necessary to meet our regulatory obligations and requirements. Unless the step change is included, the proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations.
4. Options considered
Two options have been considered to address these obligations: • Option 1. Internal resources. • Option 2. Outsource to external consultants.

5. Preferred option
The preferred option is to appoint and utilise Power and Water internal resources (option 1). As this obligation is an annual routine task, it is not economically efficient in the NT to outsource this requirement (as suitable resources are only available interstate).
6. Expenditure forecasting method
The forecast was created by calculating the incremental cost of the new obligation. The first year of expenditure is 2019-20, which is when the regulatory obligation commences. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs, which we expect the AER to use as its base year opex in the AER's final determination.
7. Expenditure forecasting assumptions
Two additional meter technicians are required from 1 July 2019 to enable the scheduled inspection and test obligations to be fulfilled. These people will be required to undertake field inspections and testing of metering equipment in the Northern and Southern Regions in accordance with the Australian Standards and AEMO guidelines. Each technician would be required for 100% utilisation per year. The forecast expenditure on the internal resources are costed as follows: • available hours of 1 person = 1,668[6] (2017-18 budgeted personnel costs and inclusive of salary on-costs); • hourly wage rate of meter technician = $91.59[7] (2017-18 budgeted personnel costs and inclusive of salary on-costs); and • total annual expenditure = $305,544 (2 x 1668 x $91.59) (2017-18$).
8. Step change benefits
Benefits include: • customer billing inaccuracies due to meter inaccuracies are virtually eliminated. This will minimise the turnaround of retailer / customer billing complaints • our revenue is proactively protected by integrity of the metering fleet and the visible presence of our staff on site performing the tests.
9. Classification of cost
The costs will be classified as routine maintenance.

[6] Ibid.

[7] Ibid.

Metering compliance type 1-6

1. Description

Each year, we must prepare and maintain a five-year rolling sampling plan for type 1-6 metering installations for our Northern and Southern Regions and assess against that plan.

2. Driver of the step change - compliance

Compliance is required with the many process obligations imposed by Chapter 7A of the NT NER. These obligations require a dedicated project to ensure that compliant processes are established and maintained. This is imperative when a substantive change is required over a relatively short timeline.

To demonstrate compliance, the Metering Services team must:

- establish the conditions (the design and socialising of processes and practices) for meeting the obligations imposed by Chapter 7A; and
- routinely monitor the extent to which it achieves compliance.

Establishing the conditions will require a one-off project to be undertaken in 2017-18 and 2018-19. Once the conditions are set for compliant practices there are two routine tasks to be performed in each year of the next regulatory period:

- annually prepare and maintain a five-year rolling sampling plan for Chapter 7A for the Northern and Southern Regions. The utilisation of the person who will perform this task is estimated to be 2-weeks per year; and
- assess compliance of metering work in accordance with that plan. The utilisation of the person who will perform this task is estimated to be 10 weeks per year (5 weeks Northern Region; 3 weeks Southern Region and 2 weeks for the report).

If the same person was to perform both tasks, the duration would be 12 weeks (3 months) per year.

3. Strategic alignment

This step change aligns with our compliance policy and Corporate vision, and is necessary to meet our regulatory obligations and requirements.

Unless the step change is included, our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations.

4. Options considered

Three options have been considered:

- Option 1. Internal metering services personnel.
- Option 2. Outsourced to Power and Water internal audit personnel.
- Option 3. Outsource to external consultants.

5. Preferred option
The preferred option is to appoint and utilise a Metering Service internal resource (option 1). This is because an understanding of the technical culture would be beneficial in determining findings and forming views on recommendations.
6. Expenditure forecasting method
The forecast was created by calculating the incremental cost of the new obligation. The first year of expenditure is 2019-20, the first year of the regulatory obligation. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.
7. Expenditure forecasting assumptions
The forecast expenditure on undertaking compliance monitoring is costed as follows: • available hours of 1 person = 418 (or 0.25 of a year); • hourly wage rate of meter technician with audit skills = $91.59[8] (2017-18 budgeted personnel costs and inclusive of salary on-costs); • total annual expenditure for meter technician = $38,285 (1 x 418 x $91.59) (2017-18$); • total annual expenditure = $38,285 per annum; and iIt is assumed that the appointed people would be recruited for deployment in 2019-20.
8. Step change benefits
Benefits include: • we will be able to meet our Network Licence requirements for billing and to comply with Chapter 7A.
9. Classification of cost
The costs will be classified as routine maintenance.

Southern Region metering technicians

1. Description
Dedicated metering technicians (project and routine) in the Southern Region.

[8] Ibid.

2. Driver of the step change - compliance
The driver is to meet the increased regulatory obligations imposed by Chapter 7A of the NT NER in the Southern Region. The Southern Region consists of Alice Springs and Tennant Creek. Currently the metering work is performed partly by electrical tradesmen (who are also assigned other electrical fitter work) and partly by external contractors (additional resources to meet metering programmed work). Work is consequently managed in an ad hoc manner and often not prioritised. This approach is inconsistent with the compliance requirements of Chapter 7A.
3. Strategic alignment
This step change aligns with our compliance policy and Corporate vision, and is necessary to meet our regulatory obligations and requirements. Our proposed forecast opex will not achieve the objectives in clause 6.5.6(c) of the NT NER to allow us to recover our efficient cost in meeting our regulatory obligations unless the step change is included.
4. Options considered
Only one option has been considered: internal metering services personnel. Staff would be located in the relevant local area within the Southern Region, be responsible to the Senior Manager Metering Services for work programs and performance and have line management reporting to the local manager. The aim of this option is to eliminate the use of external contractors for routine work and to ensure that programmed work is completed in line with the compliance requirements of Chapter 7A of the NT NER.
5. Preferred option
The preferred option is to appoint and utilise resources that fall under the responsibility and quality guidance of the Norther Region Metering Services Senior Manager, whilst line reporting for day to day management would be the responsibility of the local manager.
6. Expenditure forecasting method
The forecast was created by calculating the incremental cost of the new obligation. The first year of expenditure is 2019-20, the first year of the regulatory obligation. This means that the amount is not reflected in our 2016-17 actual costs which form the basis of our base year opex in our regulatory proposal. Nor will it be included in our 2017-18 costs which we expect the AER to use as its base year opex in the AER's final determination.

7. Expenditure forecasting assumptions
Two additional metering technicians (100% utilisation per year) are required to be assigned to metering work (project and routine) in the Southern Region. Currently, some routine metering work is performed by electrical fitters (one in Alice Springs and one in Tennant Creek) and most of the project work is performed by contractors. The forecast expenditure on the internal resource is costed as follows: • available hours of 1 person = 1,668[9] (2017-18 budgeted personnel costs and inclusive of salary on-costs); • hourly wage rate of metering data technician = \$91.59[10] (2017-18 budgeted personnel costs and inclusive of salary on-costs); • total annual expenditure two people = \$305,544 (2 x 1,668 x \$91.59) (2017-18\$); and • it is assumed that the appointed people would be recruited in 2018-19. They will be fully deployed from 2019-20 onwards.
8. Step change benefits
Benefits arise as follows: • we will be able to meet the increased regulatory obligations imposed by Chapter 7A of the NT NER in the Southern Region; and • we will be able to meet our Electricity Network Licence requirements for billing.
9. Classification of cost
The costs will be classified as routine maintenance.

[9] Ibid.

[10] Ibid.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4. Definitions

Term	Definition
ACS	Alternative Control Service
AER	Australian Energy Regulator
CAC	Customer Advisory Council
CBA	Cost Benefit Analysis
EIP Code	Electricity Industry Performance Code
GSL	Guaranteed Service Level
MDMS	Metering Data Management System
NT	Northern Territory
NT NER	National Electricity Northern Territory Rules
Opex	Operating expenditure
SCS	Standard Control Service
UC	Utilities Commission (NT)