NTESMO

Northern Territory Electricity System and Market Operator Regulatory Proposal

2024-25 to 2026-27

About this report

Power and Water Corporation submits this Regulatory Proposal to the Utilities Commission of the Northern Territory under section 39(1) of the *Electricity Reform Act 2000 (NT)* and seeks the Commission's determination of system control and market operations charges under Section 20(1) of the *Utilities Commission Act 2000*.

This document sets out the Northern Territory Electricity System and Market Operator (NTESMO) proposed costs and regulated charges for the 1 July 2024 to 30 June 2027 regulatory period.

Part 1 of the document provides context and background:

- Chapter 1 provides background on the services provided by NTESMO to our customers.
- Chapter 2 identifies the regulatory framework underpinning this proposal, including background on the true-up of the 2024-25 tariffs and our building block approach to calculating revenues and tariffs.
- Chapter 3 provides information on how NTESMO is responding to a rapidly changing landscape including rising renewables on the energy system, increasing complexity in settling market data and regulatory uncertainty in relation to NT energy market reform.
- Chapter 4 identifies the feedback we received from customers and how we have incorporated that feedback in our Regulatory Proposal.

Part 2 of the document provides information on our actual and forecast costs, calculation of revenues and proposed smoothing, and the proposed charges for the services provided by NTESMO. This includes:

- Chapter 5 provides information on actual and forecast operating expenditure, including our methods, drivers and costs.
- Chapter 6 provides information on actual and forecast capital expenditure, including our methods, drivers and costs.
- Chapter 7 provides information on the recovery amount relating to historical costs incurred above the 2019-24 allowance.
- Chapter 8 describes our approach to calculating an opening asset base for the commencement of the next regulatory period.
- Chapter 9 sets out the key components of the calculation of revenue under our proposed building block approach and how we have considered smoothing revenue recovery over time.
- Chapter 10 sets out our proposed design of charges and indicative charges.
- Chapter 11 sets out our proposed annual arrangements for reporting, cost pass through events and price adjustments.

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A message from Power and Water's Board Chair

I am pleased to present NTESMO's 2024-25 to 2026-27 Regulatory Proposal.

Our Regulatory Proposal comes at a time of seismic change in the Northern Territory (NT) electricity systems. At the beginning of this decade, the NT Government outlined a bold plan to significantly decarbonise electricity production. By 2030, the NT Government seeks to achieve a renewable energy target where 50% of electricity consumption is met by renewable sources.

The policy objective recognises that the NT has its part to play in addressing climate change and that our global export opportunities reside in greening production chains. The timing also recognises that many of our thermal generation fleet are coming to end of life and this provided an opportunity to replace carbon-emitting electricity with solar energy. In the NT, we have one of the highest efficiencies in solar production due to our land and abundant sunshine.

The pace of transition to renewable energy has been fast paced over the last five years and will accelerate as we head to 2030. In our next regulatory period, we expect that the NT energy system in Darwin-Katherine will displace almost a quarter of our existing thermal generation with new large-scale solar farms. We also expect continued uptake of behind the meter solar from our residential and commercial customers, with more than 1 in 4 customers having solar installed by 2030.

The System Controller at NTESMO lies at the centre of ensuring a secure and efficient transition to renewables. We are navigating extraordinary challenges to maintain power security in the NT, while enabling new generation into the market. This has required a fundamental re-orientation in the System Controller's operations and systems.

Our approach to keep pace with change is consistent with our overarching corporate strategies to modernise our business and embrace a sustainable future with innovation. We have and will continue to invest in tools and systems that reduce the risk of critical system events, and which provide more opportunities to unlock lower generation in the NT power system.

Similarly, our market operator is also keeping pace with pivotal changes in the electricity market, including increased competition and smart meter data. We have invested in a new Settlements System that minimises the risk of financial uncertainty in the NT Electricity Market.

We look forward to the review of the Utilities Commission of the Northern Territory.

Peter Wilson
Chair
Power and Water Corporation

CEO foreword

NTESMO is a small fraction of the electricity bill, however it plays an enormously critical role in the NT regulated power systems. The System Controller is responsible for ensuring demand for electricity is met by secure and efficient supply at any given interval in the year. The Market Operator underpins the financial stability of the market by providing accurate and timely energy data to market participants to settle payments.

The transformative changes in the NT power systems are placing great challenges in performing our legislative functions. NTESMO is vital for shepherding the NT's accelerated transition to renewable energy. While we recognise the opportunities ahead with decarbonising the power system, the immediate challenges of a changing generation mix must be met head on. The synchronous generation that will retire over the next decade and beyond provided many security benefits to a power system including 24-7 availability, frequency and voltage control and system strength.

It is clear that System Control cannot lag behind in how we respond to power system challenges. Already in this period we have significantly revamped our operations, recruited more staff and invested in tools that help manage growing renewables on the network. While we have incurred higher costs than our allowance, this was the responsible action to take. In this proposal, we have only sought to recover a modest subset of these costs that relate to ongoing benefits to customers.

Moving forward, we have proposed proportionate and prudent investments to meet the next leg of the NT's transition to 50% renewables. In the regulatory period, we expect a significant proportion of our existing generation fleet will retire by 2027, to be replaced by large scale renewable solar farms. The complexity of decision making will grow exponentially as we seek to not only ensure adequate capacity but also to draw on new technologies such as batteries and synchronous condensers to meet the shortfall in essential services that maintain the security of the power system.

Our Regulatory Proposal includes investment in a new Territory Dispatch Engine that is critical to ensuring that System Control can continue to meet its responsibilities. The Territory Dispatch Engine is a centralised and automated dispatch tool that will replace the manual and piecemeal processes we have in place today. While it represents a significant investment, it will significantly reduce the risks of major system events and will improve the efficiency of dispatch decisions.

The Market Operator function in NTESMO has also had to evolve to meet the needs of a changing market in the Darwin-Katherine Interconnected System. We have invested in a new Settlements System to replace our bespoke Excel solution that was at end of life and could not manage the increasing data requirements of smart meters. This investment will safeguard the financial stability of Darwin-Katherine Interconnected System, enabling market participants to settle their bills.

I have been very encouraged by the views and submissions of our stakeholders who have broadly supported our responsible and measured response to a changing electricity landscape. We look forward to engaging further with stakeholders as the process continues.

Djuna Pollard
Chief Executive Officer
Power and Water Corporation

Executive Summary

NT Electricity System and Market Operator (NTESMO) services are critical to energy security and the economic efficiency of the Northern Territory's (NT) power systems. We are adapting to the transformational change including a marked acceleration in the uptake of renewable energy. Our Regulatory Proposal outlines a prudent and efficient pathway to ensuring NTESMO has the right tools, systems and processes to support the modernisation of the NT power systems.

NTESMO's role in the power system

NTESMO is a ring-fenced function of Power and Water Corporation (Power and Water). The System Controller provides the critical role of overseeing the safe, secure and reliable operation of the Darwin-Katherine Interconnected System (DKIS), Tennant Creek and Alice Springs power systems (collectively referred to as the NT Power Systems). The Market Operator facilitates settlement of market participants and registers new participants in the DKIS.

We levy regulated charges on retailers based on the energy consumption of their customers. The charges are regulated by the Utilities Commission of the Northern Territory (Commission) and currently comprise about 1.4% of the energy bill for small residential customers subject to the NT Government Pricing Order. While a small fraction of the bill, NTESMO is critical to power security and economic efficiency of the NT's power systems.

We are proposing a 3-year regulatory period from 2024-25 to 2026-27. Due to delays with developing our Regulatory Proposal, we agreed with the Commission to submit a pricing proposal for 2024-25, the first year of the new regulatory period. This was based on rolling forward our approved regulated charges for 2023-24 by inflation. This was submitted to the Commission in September 2023 and was subsequently approved. As part of this Regulatory Proposal, we will propose to recover the forecast of costs for 2024-25 in the remaining two years of the regulatory period.

Responding to a changing power system

Our Regulatory Proposal outlines an efficient pathway for NTESMO to develop the required systems, processes and tools to support the modernisation of the NT's power systems. We are responding to significant changes in our external environment including the NT power systems transition to renewable energy and changes in the volume of meter data required to settle the market.

Our investment decisions align with our legislated functions and are responsible and proportionate responses to the changing landscape. If we do not act, the NT power systems will be subject to heightened system security risk and will be on a much slower pathway to renewable energy enablement.

Shepherding the NT's transition to renewables

The NT Government has a Renewable Energy Target (RET) to deliver 50% of electricity consumption from renewable energy by 2030. The NT Government's policy objective is to reduce emissions and lower generation costs by substituting 'end of life' synchronous generation with renewable sources.

The shift from synchronous generation to renewable energy creates fundamental challenges for the scheduling and dispatch functions of the System Controller. This includes ensuring adequate capacity when solar is not available, managing volatility of demand to cover momentary dips in solar production related to cloud cover, and managing a shortfall in essential system services that have historically been provided by synchronous machines.

We have and will continue to modernise our processes, tools and systems to progressively meet the challenges. This includes developing transitional tools to meet the immediate challenges and investing in a Territory Dispatch Engine (TDE) by the end of the next regulatory period to automate and integrate our control and dispatch functions.

The TDE is the predominant driver of capital expenditure (capex) in the next regulatory period, comprising $31.1 million, approximately 75%, of forecast capex. By the end of the next regulatory period, a significant amount of synchronous generation is expected to retire and be replaced by large scale renewable energy. The System Controller will be required to manage an exponentially growing set of constraints to operate a secure and efficient level of dispatch. For this reason, we consider there is a need for an integrated real-time system to simultaneously manage all the factors impacting the power system. The TDE will automate current processes which are highly manual, such as the processing of bids from market participants. It will also provide mechanisms that allow System Control to manage renewable generation whilst still optimising economic dispatch.

Prior to the implementation of TDE, we have developed and will continue to evolve our existing suite of transitional tools to meet new emerging challenges. We forecast capex of $6.1 million on evolving transitional tools in the next regulatory period. The tools will improve the granularity of our demand forecasts including more geographic information on cloud cover, identify shortfalls in essential system services, and improve how we monitor and dispatch large scale generation. The transitional tools serve as a fundamental building block for the TDE. In the absence of these tools, the TDE project costs would be much higher.

In addition to the capex forecast, additional resources have been included to support the ongoing operation of the tools, increased generation connections and the ongoing training requirements.

Our actions will reduce the risk of major power interruptions, improve the efficiency of dispatch decisions, and enable the secure entry of new renewable sources into the power systems.

Settlements System that accommodates increased smart meters

The Interim NT Electricity Market (I-NTEM) is also transforming with increasing generation competition. In this context, it is vital that the Market Operator can provide accurate and timely information on energy consumption to facilitate prompt settlement of contracts between market participants. This has proven increasingly complex due to the exponential increase in energy data associated with the rapid uptake of smart meters in the NT.

We have responded in the current regulatory period by implementing a new Settlements System to replace a bespoke Excel solution that had not kept pace with the increase in data requirements. The investment in the Settlements System is forecast to cost $3.1 million capex in the current period. Its implementation will significantly reduce financial risk to system participants from delayed settlement activity, particularly given the expected full roll-out of smart meters in the NT by 2029. The Settlements System has been designed to be adaptable to the NT Government's NT Electricity Market Priority Reform Program (NTEM reforms).

We are also forecast to incur a residual $0.4 million on the new Settlements System in the next regulatory period. The Settlements System's ongoing operational expenditure (opex) of $0.7 million per annum have been included in the forecast for the next regulatory period.

Regulatory reforms

The NT Government is pursuing NTEM reforms to ensure regulation keeps pace with changes in the power system. NTESMO provides support to the reform process through its legislated function to review and propose changes to the System Control Technical Code (SCTC). We have also been actively engaging with the NT Government on the design and development of the NTEM reforms through the provision of technical advice and delivery of studies. The benefit of NTESMO engagement in this regard supports regulatory reform that is fit for purpose, particularly in respect of technical regulations that impact the security and efficiency of the power system. We have forecast $0.4 million opex to continue the support role into the next regulatory period, but we have assumed that the NT Government will lead the rule drafting and stakeholder engagement processes.

We have listened to our stakeholders

In developing our Regulatory Proposal, we consulted with market participants, major customers and customer representatives.

In our first round of consultation, we sought feedback on the framework and approach for the Regulatory Proposal and options for our future direction. In our second round of consultation, we sought feedback on our initial calculation of regulated charges including drivers and options for cost recovery. To elicit feedback from stakeholders we prepared consultation papers and received written submissions. We also held two stakeholder workshops and conducted 'one on one' feedback sessions. The views of our stakeholders have been considered and incorporated into this Regulatory Proposal.

Forecast revenue

We have used a building block approach to forecast revenue requirements in the 2024-25 to 2026-27 period. This includes an annual operating expenditure allowance, and a return on and of capital related to the value of the Regulated Asset Base (RAB). All expenditure and revenue has been expressed in 2023-24 real dollars. A breakdown of the forecast capex and opex drivers is provided below.

Figure 1 - Forecast opex by cost category ($m, real 2023-24)

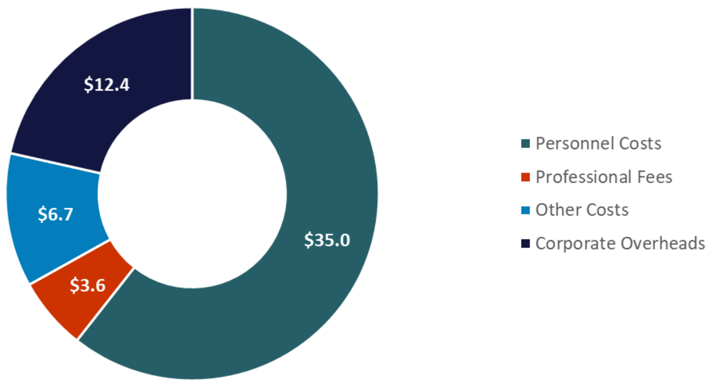
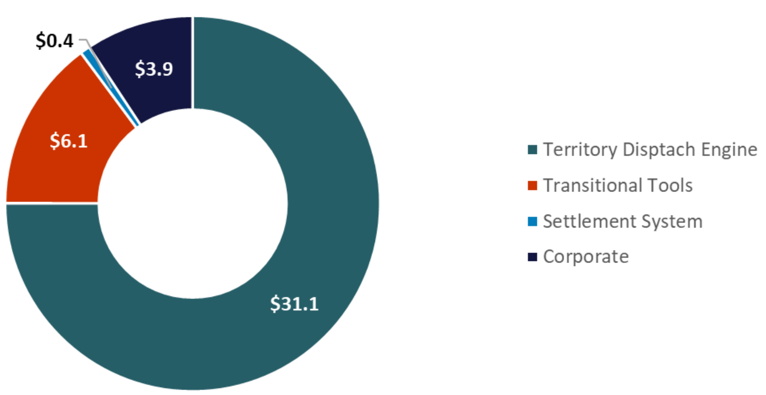


Figure 2 - Forecast capex by cost category ($m, real 2023-24)



The RAB comprises the depreciated value of historical and forecast capex. We have calculated a return on capital consistent with the approach used for regulating Power and Water's regulated network services including the rate of return value. **Tables 1 and 2** show the building blocks revenue requirement calculation for System Control and Market Operator in nominal terms.

Table 1 - Breakdown of System Control revenue for 2024-25 to 2026-27 ($m, real 2023-24)

	2024-25	2025-26	2026-27
Capex	14.4	13.8	12.7
RAB (Opening Value)	16.0	29.2	40.6
WACC (Nominal Vanilla)	5.61%	5.74%	5.88%
Return on capital	0.9	1.7	2.4
Return of capital (Depreciation)	0.9	1.8	2.7
Opex	16.6	16.5	15.7
Building Blocks Revenue Requirement	**18.4**	**22.8**	**23.7**

Table 2 - Breakdown of Market Operator revenue for 2024-25 to 2026-27 ($m, real 2023-24)

	2024-25	2025-26	2026-27
Capex	0.4	0.1	0.1
RAB (Opening Value)	3.7	3.8	3.6
WACC (Nominal Vanilla)	5.61%	5.74%	5.88%
Return on capital	0.2	0.2	0.2
Return of capital (Depreciation)	0.2	0.2	0.3
Opex	3.5	3.5	2.8
Building Blocks Revenue Requirement	**3.9**	**5.3**	**5.5**

Proposed annual revenue requirements

Table 3 below sets out the expected and proposed revenue amounts for System Control and Market Operator, allowing for adjustments to the building blocks for the true-up in 2024-25 and recovery of a subset of unfunded costs in 2019-24.

Table 3 – Expected and proposed annual revenue requirements ($m, real 2023-24)

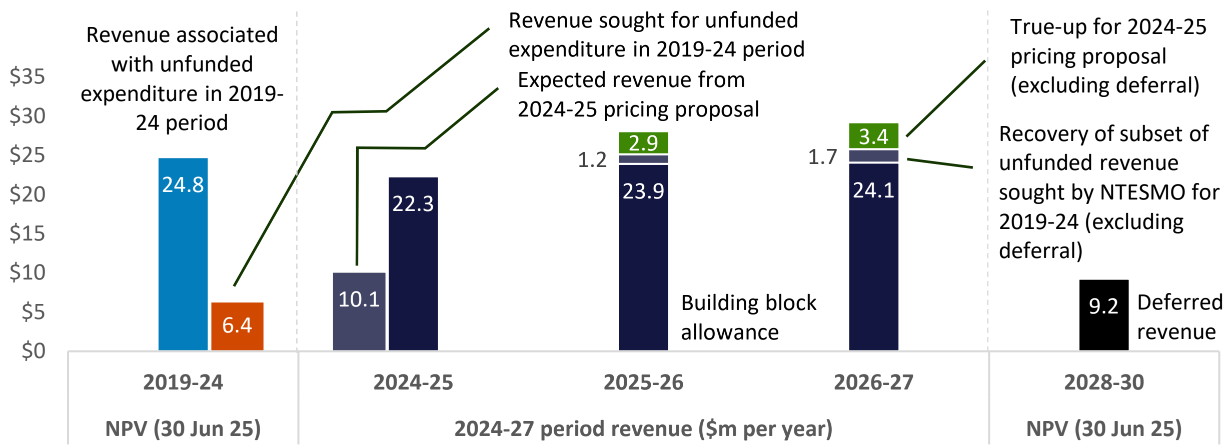
	2024-25	2025-26	2026-27
System Control	9.3	22.8	23.7
Market Operator	0.8	5.3	5.5
Total	**10.1**	**28.1**	**29.2**

This reflects that prices for the first year of the next regulatory period have already been approved by the Commission based on an interim calculation that rolled-forward 2023-24 approved prices by inflation. In effect, this established an expected revenue for that year based on energy consumption forecasts. This means that this Regulatory Proposal can only include a revenue forecast for the 2025-26 and 2026-27 years. In calculating our annual revenue requirement, we have made the following adjustments:

- **Subset of unfunded costs in 2019-24** – We have sought additional revenue of $6.4 million relating to the $24.8 million of revenue associated with unfunded expenditure above the Commission's allowance in the 2019-24 period. Of the NPV adjusted recovery amount we have sought to include $1.2 million in 2025-26 and $1.7 million in 2026-27, with the additional amount deferred to the following regulatory period. Spending above the allowance was critical to maintain the security of the power systems, facilitate the NT's transition to renewable energy and ensuring settlement was timely and accurate. Based on stakeholder feedback we have only sought compensation for investments that will continue to provide benefit to customers in future periods including Settlements System and transitional tools. In total, we have only sought recovery expenditure of $17.1 million of the total $38.9 million incurred above the Commission's allowance.
- **True up for 2024-25 prices** – We have sought to 'true up' the expected under-recovery in the 2024-25 first year of the regulatory period of $12.2 million, including an adjustment for net present costs. This reflects that the building block forecast for 2024-25 is much higher than the expected revenue in the approved prices. Of the NPV adjusted recovery amount we have sought to include $2.9 million in 2025-26 and $3.4 million in 2026-27, with the additional amount deferred to the following regulatory period.
- **Deferral amount** - To minimise price impacts on customers we have deferred recovery of 50% ($9.2 million) of the true-up and retrospective costs identified above. We propose to recover this amount in the first three years of the following regulatory period. This followed feedback received from stakeholders.

Figure 3 identifies the expected revenue in 2024-25 under the pricing proposal relative to the building block allowance, and the forecast revenue for 2024-25 and 2025-26 based on the building block forecasts, true-up of 2024-25 revenue recovery, and the retrospective revenue. We have set this out in real terms.

Figure 3 – Revenue requirements ($m real 2023-24)



Regulated charges and bill impacts

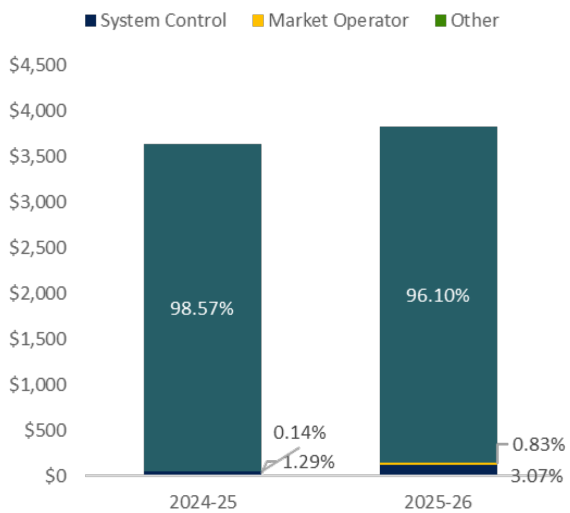
Annual regulated charges are calculated based on the annual revenue requirement divided by the annual forecast energy consumption. **Table 4** identifies the proposed regulated charges which are expressed in nominal dollars. Consistent with the increase in forecast revenue in 2025-26 and 2026-27, we are forecasting an increase in regulated tariffs for both System Control and Market Operator.

Table 4 – Indicative regulated charges for System Control and Market Operator (c/kwh, nominal)

	2024-25	2025-26	2026-27
System Control	$0.005527	$0.013837	$0.014744
Market Operator	$0.000585	$0.003719	$0.003963

NTESMO comprises a very low proportion of the electricity bill of NT customers. In the last year of approved prices (2024-25), System Control and Market Operator's combined impact was 1.4% of the annual electricity bill of a small residential customer in the DKIS. Despite the increase in proposed regulated charges in 2025-26, the combined impact is still very low at 3.9%. **Figure 4** shows the change in composition of System Control costs, assuming all other costs in the NT power systems stay constant in real terms.

Figure 4 – NTESMO's contribution to typical Darwin-Katherine residential electricity bill -comparison of 2024-25 to 2025-26



1. NTESMO’s services

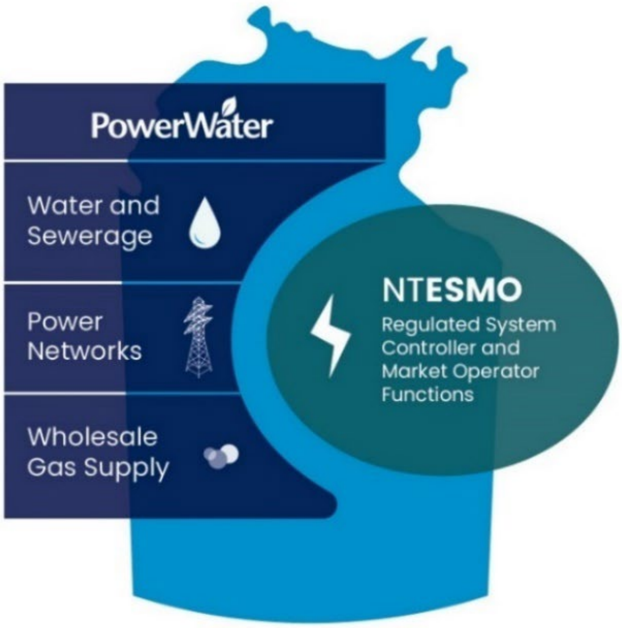
NTESMO is responsible for controlling the NT regulated power systems and settling the electricity market in Darwin-Katherine. The System Controller is critical to keeping the NT power systems in a secure operating state 24 hours a day. The Market Operator registers market participants and provides energy data to generators and retailers to facilitate market settlement.

The purpose of this Chapter is to identify NTESMO’s role in the NT power systems, and the functions we perform. This includes our underlying regulatory obligations and activities.

1.1 NTESMO’s role in the NT Market

NTESMO is responsible for power system control and market operator functions in the NT[1]. We are a ring-fenced function of Power and Water as illustrated in **Figure 5**. Our functions are set out in Section 38 of the *Electricity Reform Act 2000* (ER Act), the System Control Technical Code (SCTC) and the Northern Territory National Electricity Rules (NT NER). These functions are performed under the System Control Licence granted to Power and Water.[2]

Figure 5: NTESMO function ring-fenced within Power and Water Corporation



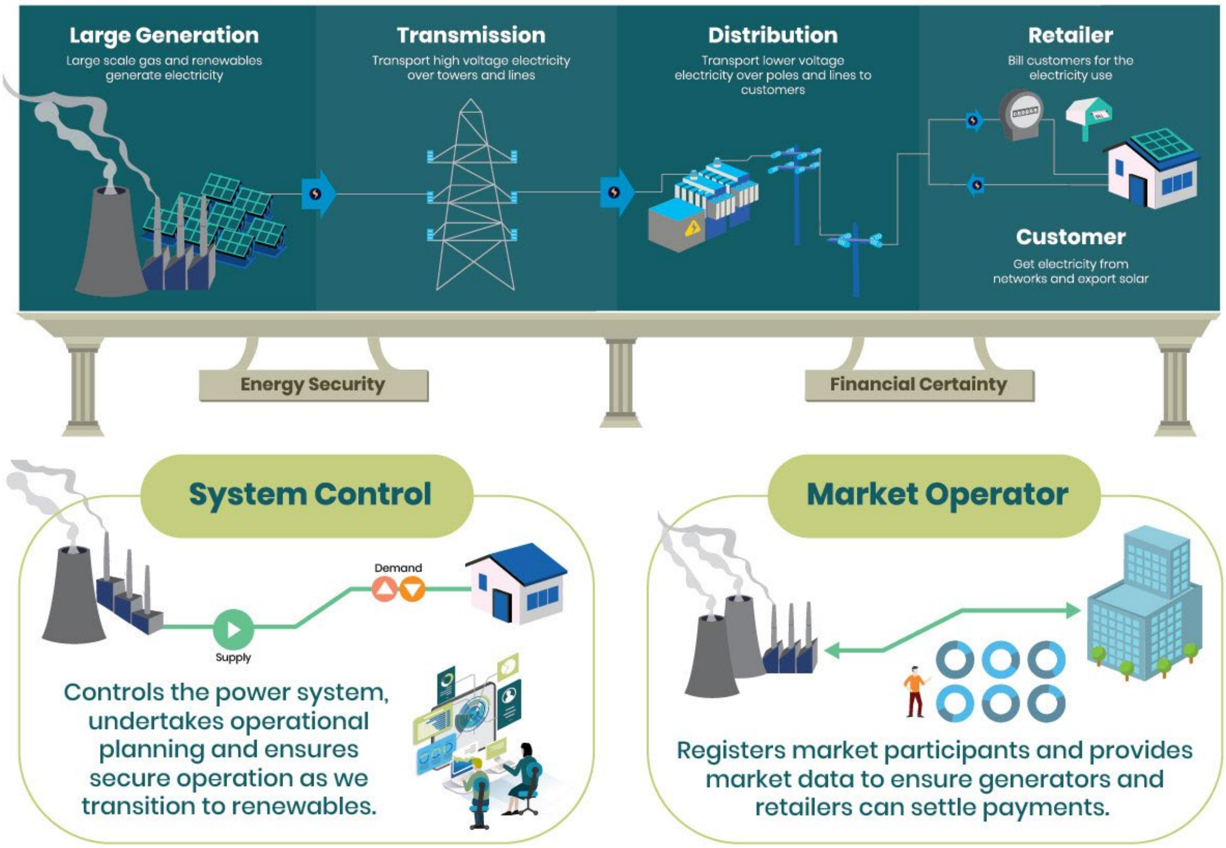
[1] The three electricity systems that Power and Water is responsible for under its System Control Licence are: Darwin-Katherine interconnected system, Alice Springs power system and Tennant Creek power system. The System Control Technical Code is published on the NTEMSO website.

[2] The National Electricity Rules (NT) refers to the Northern Territory Electricity System and Market Operator (NTESMO) as a collective term for the entity that either controls the operation of the power system or administers the market arrangements. The term ‘NTESMO’ is used to refer to the system controller and market operator functions that Power and Water is licenced to perform under its System Control Licence which is published on the Utilities Commission Website.

As System Controller, NTESMO plays a critical role in ensuring the reliability and security of the NT power systems in DKIS, Tennant Creek and Alice Springs. Its primary responsibility is to ensure the efficient scheduling and dispatch of generating systems to provide sufficient energy supply to securely meet demand. This requires real time operation and control, forecasting, planning, and reporting. The Market Operator is responsible for registering market participants and 'virtual settlement' in the DKIS I-NTEM, enabling financial certainty for market participants.

Figure 6 illustrates the System Controller's and Market Operator's activities in the NT power systems.

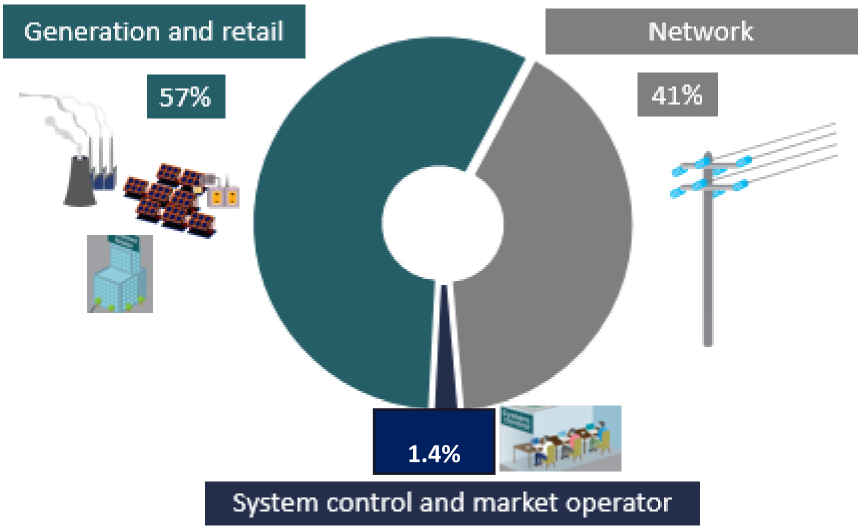
Figure 6 – NTESMO's role in the power system



NTESMO charges comprise a very small portion of a customer's electricity bill as illustrated in **Figure 7.** For residential customers in DKIS who are not subject to the Electricity Pricing Order[3], the NTESMO charge is currently 1.4% of the total electricity bill.

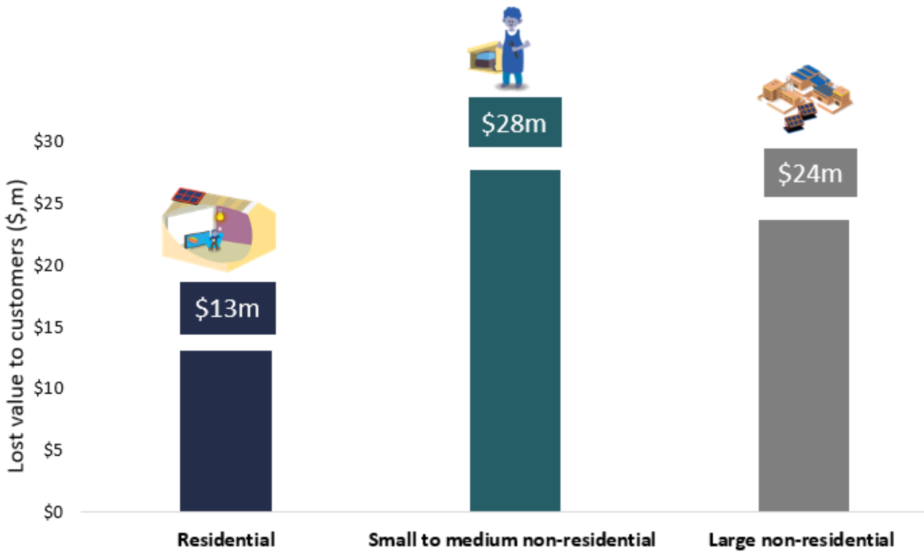
[3] Section 44 of the ERA provides that the Minister may issue an electricity pricing order

Figure 7 – Contribution of sectors to the energy bill of a typical residential customer (%)



The value and criticality of our System Control functions is underscored by the consequence of power system outages. For example, an eight hour outage in DKIS is estimated to impact the economy by $60 million due to the loss of value experienced by small and large electricity customers[4]. **Figure 8** demonstrates the loss in value by customer type.

Figure 8 – Loss in value to customers from an 8 hour outage in Darwin-Katherine ($ million, nominal)



[4] This has been based on the AER's methodology for deriving a lost value for outages in the NT. Please see AER Website

1.2 Our regulatory obligations

Power and Water is responsible for undertaking System Control and Market Operator functions across the NT power systems in accordance with Section 38 of the ER Act. These functions are performed under Power and Water's System Control Licence (licence) granted by the Commission.

The licence requires NTESMO to comply with the SCTC.[5] The SCTC sets out:

- Requirements to maintain and achieve a secure system.
- Procedures for generation plant scheduling and ancillary services.
- Requirements relating to the operation of, and equipment connected to, a power system.
- Quality of supply standards which apply at connection points to a power system and the requirements placed on system participants to ensure that the technical performance of an interconnected power system meets all the requirements of the SCTC and Network Technical Code.[6]
- Market Operator responsibilities under the I-NTEM in the DKIS.

1.3 Our functions and activities

NTESMO provides regulated and unregulated services.[7] This proposal only identifies costs for regulated functions. **Figure 9** identifies the key functions we perform as the System Control and Market Operator including:

- Real time operations (System Control) – This involves monitoring and controlling the system in near real time including dispatch activities, controlling activities, testing activities and monitoring generation and system participants.
- Operations Planning (System Control) – This includes undertaking short term planning and reporting that assists in providing a secure power system, including generator connections, incident reporting, load forecasting and technical compliance and directions.
- Power System Evolution (System Control) – This is a relatively new function to enhance renewable integration, development of operational tools to support growing renewables and new operational procedures.
- Market Operations – This involves registering market participants and undertaking analysis on customer's energy consumption in order that retailers and generators can settle their bills.
- NTEM reform and policy development (Market Operator) – This involves providing policy makers with technical advice on issues relevant to our functions that are used for NTEM reform and other policy initiatives of the NTG such as renewables.

Attachment 5.1 sets out our activity allocation and obligation mapping. We note that these are used to allocate the personnel costs as discussed in Chapter 6.

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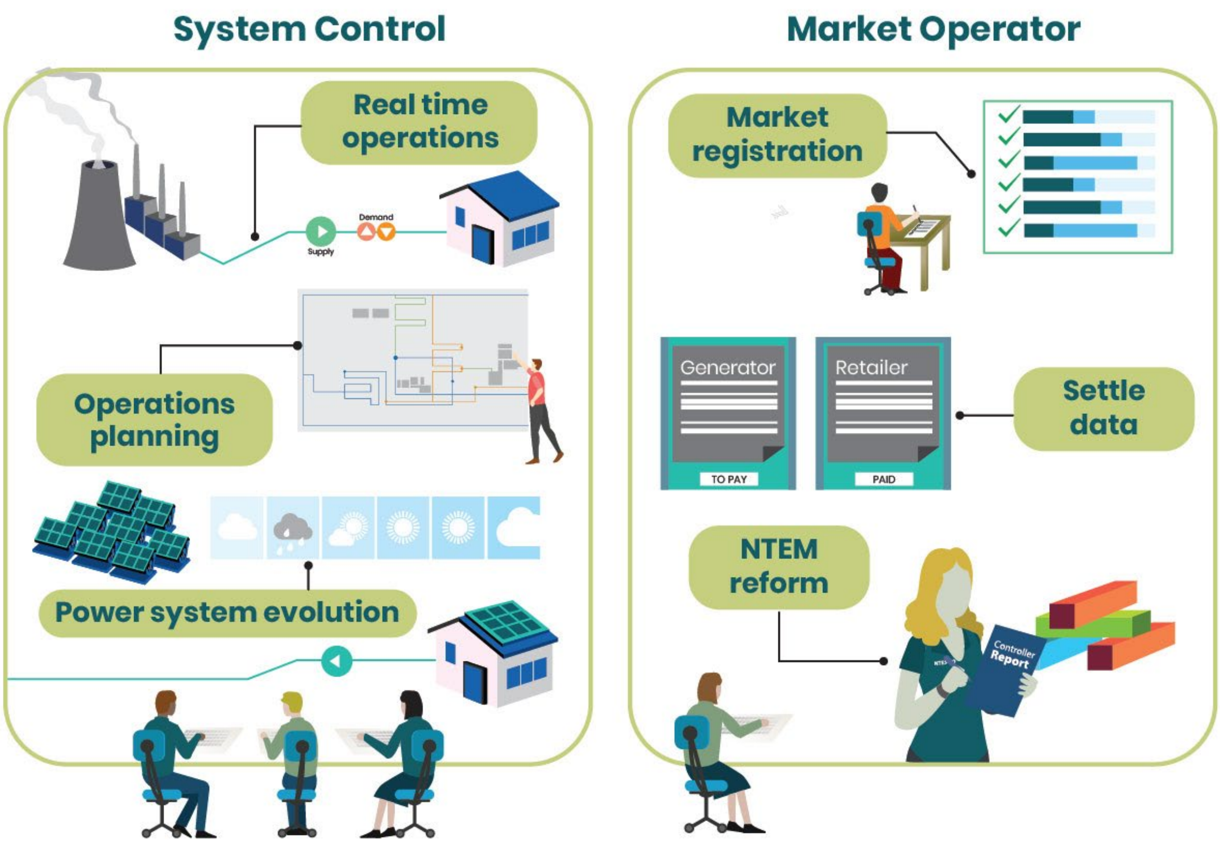
5 Sections 11.1(a) and 15 of the licence.

6 Refer to section 1.2 of the SCTC.

7 NTESMO provides unregulated services to Power Services, Water Services and Territory Generation. The costs of these services are not a part of this Regulatory Proposal.

Figure 9 – Functions undertaken by System Control and Market Operator



2. Framework and Approach

We are proposing a three-year regulatory period from 1 July 2024 to 30 June 2027. We propose to use the 'building block' approach to determine our revenue requirements. We propose to include a subset of our unfunded costs from the 2019-24 period, together with applying a 'true-up' for the 2024-25 first year of the proposal. We have proposed pass throughs to recover efficient costs arising in the next regulatory period for events that are uncertain in scope and timing.

The purpose of this Chapter is to identify the economic regulatory framework that applies to NTESMO, and our approach to developing this Regulatory Proposal. This includes the length of the regulatory period, the basis for calculating our proposed regulated charges, the key inputs underpinning our calculations, and the inclusion of a pass-through mechanism for events that are uncertain in terms of scope and timing.

2.1 NT Electricity Pricing Regulatory Framework

The ER Act sets out the objectives of the NT's electricity regulatory framework and provides for the remuneration of the System Controller, specifying it must be approved by the Commission. The *Utilities Commission Act 2000* (UC Act) identifies the Commission's requirements in exercising its functions, including making pricing determinations.

Section 6(2) of the UC Act states:

'In performing the Utilities Commission's functions, the Utilities Commission must have regard to the need:

> *(a) to promote competitive and fair market conduct;*
>
> *(b) to prevent misuse of monopoly or market power;*
>
> *(c) to facilitate entry into relevant markets;*
>
> *(d) to promote economic efficiency;*
>
> *(e) to ensure consumers benefit from competition and efficiency;*
>
> *(f) to protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries;*
>
> *(g) to facilitate maintenance of the financial viability of regulated industries; and*
>
> *(h) to ensure an appropriate rate of return on regulated infrastructure assets.'*

In developing, consulting on and refining this Regulatory Proposal, we have considered these requirements, and pursued an approach that we consider will best achieve them.

Under the UC Act the Commission has significant discretion in making revenue determinations.[8] In the absence of detailed regulatory requirements, we have sought to outline and follow a robust regulatory pathway that is in our customers' interests. This includes the length of the proposed regulatory period and the forecasting and cost recovery methods applied. Additionally, in so far as practical, this approach is consistent with the Australian Energy Regulator's (AER) approach for determining revenue allowances for our network services.

2.2 Regulatory period including transitional arrangements for 2024-25

The Commission has provided us with an opportunity to propose a framework on the application of the next regulatory period. Below we set out our proposed arrangements including a shorter three year period, transitional arrangements of the first year of the proposal, and the inclusion of a draft decision and revised proposal.

Shorter three year period

We are proposing a three-year regulatory period commencing from 1 July 2024 to 30 June 2027. While this is a shorter period than the current regulatory period of five years, we consider a three-year regulatory period provides the right balance of pricing certainty and cost uncertainty. This is particularly important given the NTEM reforms and rapidly changing power system. As discussed in Chapter 4, stakeholders were generally supportive of this proposed approach.

The key reason for proposing a three-year regulatory period is the ongoing rapid technology and market changes impacting the power system, and uncertainty with the timing and scope of the NTEM reforms. We expect that in the coming two years the impact of major NTEM reforms on NTESMO will be better understood and we will be in a more informed position to forecast capex and opex requirements in the medium term.

We will also be in a better position to engage with our stakeholders on changes to our costs following NTEM reform and explore options in readiness for the following regulatory period. This approach also allows Power and Water to efficiently utilise existing resources by better staging the timing of the NTESMO proposal and electricity network regulatory proposal.

Transitional arrangements for the first year of the regulatory period

Given the timing delay in submitting this proposal, the Commission agreed that NTESMO could submit interim charges for the first year of the regulatory period (2024-25). In September 2023 NTESMO submitted its 2024-25 Annual Pricing Proposal which sought to escalate charges for 2023-24 to account for inflation (based on the Australian Bureau of Statistics' June quarter 2023 consumer price index, weighted average of eight capital cities). On 3 November 2023 the Commission agreed to this escalation approach and approved the System Control and Market Operator charges for the period 1 July 2024 to 30 June 2025. The Commission's decision has been published on its website.

[8] In making a determination under section 20(1)(a), the Commission must (in addition to having regard to the general factors specified above) have regard to: the costs of making, producing or supplying the goods or services; the costs of complying with laws or regulatory requirements; the return on assets in the regulated industry; any relevant interstate and international benchmarks for prices, costs and return on assets in comparable industries; the financial implications of the determination; any factors specified by a relevant industry regulation Act or by regulations under this Act; and any other factors that the Utilities Commission considers relevant.

In this Regulatory Proposal, we provide detail on forecast costs for the 2024-25 year. The purpose is to ensure that there is a 'true-up' to reflect the revenue that would have been approved in the 2024-25 year.

Arrangements for draft decision and revised proposal

We propose that the Commission provide a draft decision in September 2024. This would enable both NTESMO and stakeholders to provide feedback on the draft decision. We consider that NTESMO should be provided an opportunity to revise its proposal in December 2024 in light of the Commission's draft decision and any new information. This would provide sufficient time for the Commission to finalise its regulatory determination by 31 March 2025. This approach is closely aligned to the AER's prescribed approach for electricity network services, and in our view is 'best practice' to allow NTESMO to respond to aspects of the Commission's draft decision.

2.3 Methodology to determine regulated charges

Regulated charges have been calculated by forecasting the efficient revenue to be recovered from customers over the next regulatory period and then dividing by the energy consumption to derive a cents per kilowatt hour charge.

Building block approach to forecast revenue

In our last regulatory proposal, our regulated revenue and charges were based on forecast operating expenditure only. This included costs for personnel and professional fees. These costs were largely based on NTESMO's cost structure at the time, which was based on a simple control room model with minimal engineering support. These forecasts did not include what were considered at the time to be 'speculative costs' such as the need to modernise our systems in light of NTEM reform.

The approach reflected the relative immaturity of the regulatory process, the expectation that NTEM reform was imminent, and the significant step change it represented from the postage stamp charge that had been in place since the corporatisation of Power and Water.

For this Regulatory Proposal, we have based our revenue and charges on a building block methodology. A key difference in the building block approach is providing a return on and depreciation for capex. This is a best practice methodology used in electricity network regulation in Australia together with other regulated industries such as water and gas networks.

The building blocks approach is based on the following steps:

- Calculating forecast opex for each year of the next regulatory period in 2023-24 real dollars. The calculation considers the activities we require to meet our regulatory obligations, with consideration to escalation factors above inflation for labour. We have identified opex by the following categories - personnel, professional fees, other and the expensed component of corporate overheads. This is discussed in Chapter 5.
- Calculating forecast capex for each year of the next regulatory period in 2023-24 real dollars. This is based on a forecast of direct capex on assets used by NTESMO, corporate assets allocated to NTESMO such as Information, Communication and Technology (ICT) and property assets, and capitalised corporate overheads allocated to NTESMO. This is discussed in Chapter 6.
- Establishing a RAB for each year of the next regulatory period based on the depreciated value of historical and forecast capex. This is discussed in Chapter 8.
- Calculating forecast annual revenue for each year of the forecast period in 2023-24 real dollars. As described in Chapter 9, this entails calculating an:

- Opex allowance: This is based on the forecast operating expenditure for the next regulatory period.
- Return on capital allowance: This is based on the weighted average cost of capital (WACC) and the RAB in each year of the next regulatory period.
- Return of capital (depreciation) allowance: This is based on the value of the RAB and the standard and remaining lives of assets in the RAB using a straight line depreciation method.
- Tax allowance: This is the allowance for corporate tax, noting that the WACC is a post-tax value.

The building blocks methodology has been used to calculate both a historical and forecast revenue requirement. This Regulatory Proposal outlines that the approved revenue in the 2019-24 regulatory period and the first year of the next period (2024-25) was significantly less than the revenue required.

As noted in Chapter 7, the forecast revenue recovery calculation for the next period includes retrospective cost recovery for a subset of unfunded expenditure above the Commission's allowance in the 2019-24 regulatory period. We have included a 'true-up' of costs relating to the shortfall in revenue between the approved prices in 2024-25 (first year of the proposal) and the forecast revenue under the building block approach in the proposed revenue for 2025-26 and 2026-27. To minimise customer impact, we have as a final step, sought to defer a portion of the cost recovery to future periods. We propose that the deferred portion be recovered over the first three years of the following regulatory period.

Energy consumption forecast

The revenue recovery calculation for the 2024-27 regulatory period (as described above) has been divided by the energy consumption forecast to calculate the regulated charge for 2025-26 and 2026-27. This has been expressed in nominal dollars. For the System Control regulated charges, we have used the energy forecasts relating to the DKIS, Tennant Creek and Alice Springs regulated networks. For the Market Operator regulated charges, we have used the energy forecast for the DKIS only. We note that we have included a proposed under and over recovery mechanism that includes updates for actual energy consumption.

2.4 Key inputs and assumptions

Unregulated costs

As outlined in Chapter 1, NTESMO provides several unregulated services both within Power and Water and more broadly to the electricity industry. These services provide operational efficiencies that benefit our customers and stakeholders. We have excluded the costs associated with these unregulated activities when developing our forecast regulated charges. This includes services such as our 24 hour control room dispatching crews and providing outage notifications for our network and water businesses, and where we provide settlement functionality for the systems outside of the I-NTEM to Territory Generation[9] (TGen). These unregulated costs include a portion of corporate overhead costs, ICT and professional fees along with labour costs.

As discussed below, we used an activity based approach to map our costs to functions provided under the SCTC and show how costs have been allocated to unregulated activities.

[9] Power Generation Corporation established by the *Power Generation Corporation Act 2014*, trading as Territory Generation

Activity cost modelling – personnel costs

Personnel costs are the majority of NTESMO's costs. In our last proposal, we set out the time each staff member took over 70 activities. The process was very detailed compared to best practice regulation such as the AER's review of operating expenditure in the national electricity market.

In June 2022, we proposed an alternative to the Commission. The approach was to simplify the reporting methodology in the next regulatory proposal, reducing the number of activity classifications moving us closer to modern regulatory practices. We have adopted this approach for this Regulatory Proposal, and will continue to refine this approach for the following proposal. Further detail is provided in **Attachment 5.1**.

Each cost category has been mapped to either System Control or Market Operator Charge based on activity type. The underlying principle to be applied when selecting the charge is the appropriate recovery mechanism the expenditure is relating to:

- Development and operation of the I-NTEM and full NTEM (DKIS specific obligations) - recovery through the Market Operator Charge.
- Operation of all three regulated grids– recovered through the System Control Charge. This includes activities required to enable the power system evolution.

This approach has been applied to actual personnel costs in 2022-23 and underpins the forecast personnel costs.

Inclusion of retrospective costs in revenue

We incurred higher expenditure in the current regulatory period to the allowance provided by the Commission. The assumptions underlying our 2019-24 proposal and the Commission's subsequent determination was that:

- Renewable energy uptake was likely to accelerate as we neared 2030 but would not increase significantly in the 2019-24 determination period.
- The current systems and personnel would be adequate until the NTEM reforms occurred.
- NTEM reforms would occur in the 2019-24 regulatory period and would address the transition to renewables reform and system requirements.

Since the Commission's 2019-2024 determination, there have been significant change factors that required us to incur additional costs. These largely relate to the need to manage increasing renewable technologies in the NT power systems, the need to update our settlements system to meet our compliance obligations, and the need to support rule developments and NTEM design. In the absence of expected NTEM reform, there was no trigger to recover these additional costs.

Undertaking these activities in the current regulatory period was critical to maintain the stability and efficient operation of the power system. In the absence of these investments, customers would have faced a much higher risk of prolonged outages, and higher generation costs. Further, we would have not been able to ensure settlement of the market in DKIS. Given the risks involved, we proceeded with the activities despite the risks of being unable to recoup our costs at a later point in time.

In our discussions with stakeholders, we sought feedback on principles we should apply in determining which costs should be recovered retrospectively. Chapter 7 of this Regulatory Proposal sets out how we applied principles and the costs that we are seeking retrospectively.

Re-mapping our General Ledger and capitalisation of costs

We used our general ledger as the source of actual expenditure for System Control and Market Operator costs for 2019-23. We have made several adjustments to the data:

- We have re-mapped costs to the appropriate service, and developed a new service termed "Power System Evolution".
- We have re-categorised expenditure on assets from opex to capex. This was based on determining costs that related to the development and implementation of an asset that provides a service for longer than a year including transitional tools, development of the Settlements System business case, and development of the TDE business case. This treatment varied from our statutory accounting treatment, which is restricted due to the assets being considered intangible and developed largely in-house.

Approach to capitalisation

We have adopted a pragmatic approach to capitalisation and have sought to balance customer price outcomes with accounting standards. Our approach varies from the accounting standards used for statutory reporting. We have adopted the principle that if the initiative provides value beyond the year the costs are incurred, then it should be treated as an asset and costs recovered over its useful life. Further information is available in **Attachment 5.2**.

The approach we adopted is in line with stakeholder feedback, which indicated a preference for deferring revenue recovery to minimise customer price shock. If a more conservative approach is adopted and these costs were treated as opex, these costs would be recovered in the year incurred. This would result in larger price increases than already forecast.

Should the Commission choose not to accept the capitalisation approach, expenditure will revert to opex which will have a direction impact on the required revenue. NTESMO would welcome the opportunity to discuss with the Commission how best to manage customer impact if the Commission takes this approach.

Corporate overheads

We have used the AER's approved Cost Allocation Method (CAM) to allocate corporate overhead costs to the Core Operations business unit (NTESMO parent business unit), which is at **Attachment 2.1**. We have subsequently developed a Core Operations CAM, which provides a further allocation to regulated System Control and Market Operator functions. Similarly, we have applied the Power and Water corporate overhead capitalisation method in this Regulatory Proposal to determine the proportion of corporate overheads that are capitalised and expensed. Further information is provided in **Attachment 2.2**.

Approach to business cases

The Commission provided NTESMO with a document outlining its minimum expectations regarding business cases for capital projects. Power and Water's Project Investment Delivery Management Standard provided at **Attachment 2.3** (PIDF) provides a robust framework within which investment decisions are made. Given our two major investments; the TDE and evolving transitional tools; are currently in the planning stages, we do not have final approved business cases in accordance with the PIDF. We expect to be able to provide approved business cases to the Commission by the time of our revised proposal.

Noting that both the Commission and stakeholders require project justifications, we have utilised an existing document template termed a Regulatory Business Case (RBC) that was recently used in the regulatory proposal to the AER for electricity network services. The RBCs provide a justification of the need, an examination of options, and an estimate of the likely cost based on high level scope. The RBCs are subject to review by our Enterprise Portfolio Management Committee (EMPC) and have been endorsed for submission to the Commission in support of this Regulatory Proposal.

2.5 Managing uncertainty through pass throughs

There is considerable uncertainty on the timing and scope of NTEM reform. Our Regulatory Proposal does not include expenditure related to the requirements of implementing future reform. While the NT Government has four clear priority areas, these have recently been under review and there is little information on the requirements and timing of new obligations.

We also consider there is uncertainty on whether a major system event may occur in the next regulatory period, similar to the Alice Springs System Black that occurred in the current regulatory period. As such the costs associated with investigating and actioning the subsequent recommendations have not been included in the forecast.

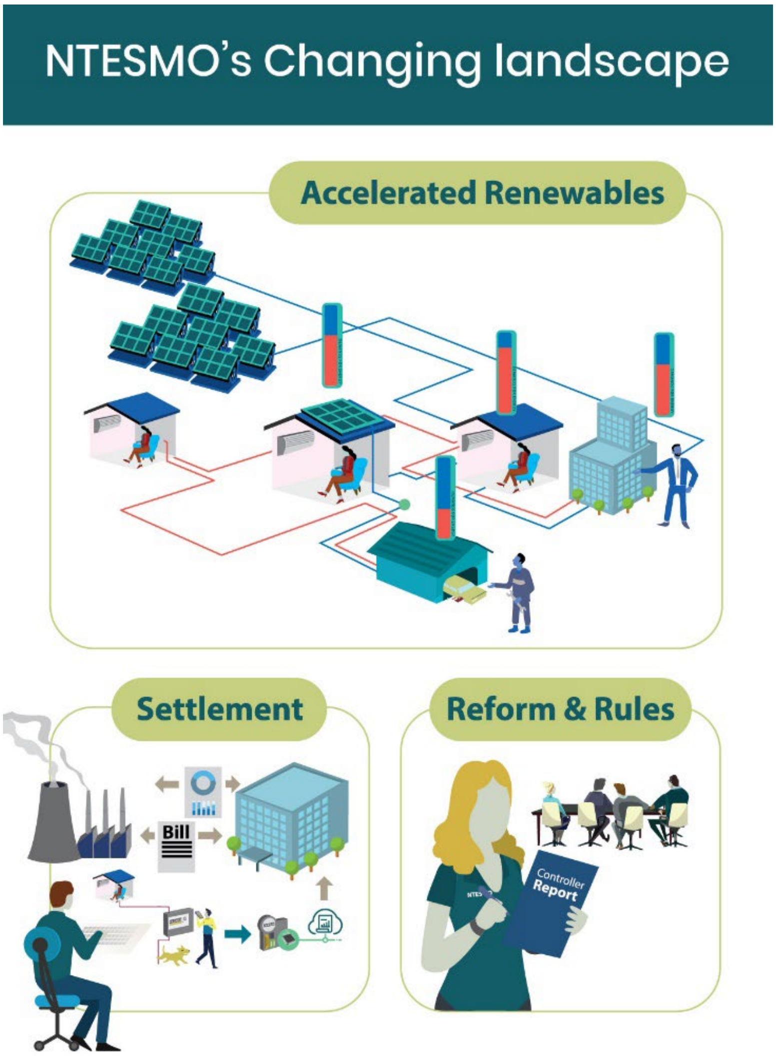
For this reason we are proposing the pass-through mechanism similar to that utilised in the AER framework for network regulation. In Chapter 11, we identify nominated pass-through events for the next regulatory period. We set out the proposed operation of the pass through mechanism including the oversight of the Commission in allowing costs to be passed through.

3. Changing landscape

NTESMO is responding to changes in the NT power systems and market. These changes include an accelerated transition from synchronous generating plant to renewable generation, and an exponential increase in data volumes to settle the market. We have been responding to change in the absence of planned reform of the NT power systems.

This Chapter details how NTESMO has been responding to transformational changes in our operating environment. This includes managing the modernisation of the NT power systems as we transition from reliance on synchronous generating plant to renewable resources and supporting technologies. We are also managing increasing volumes and complexity of data required to settle the market, and ensuring we amend the SCTC and provide technical support to the NT Government for regulatory reform. The key drivers can be seen in **Figure 10**.

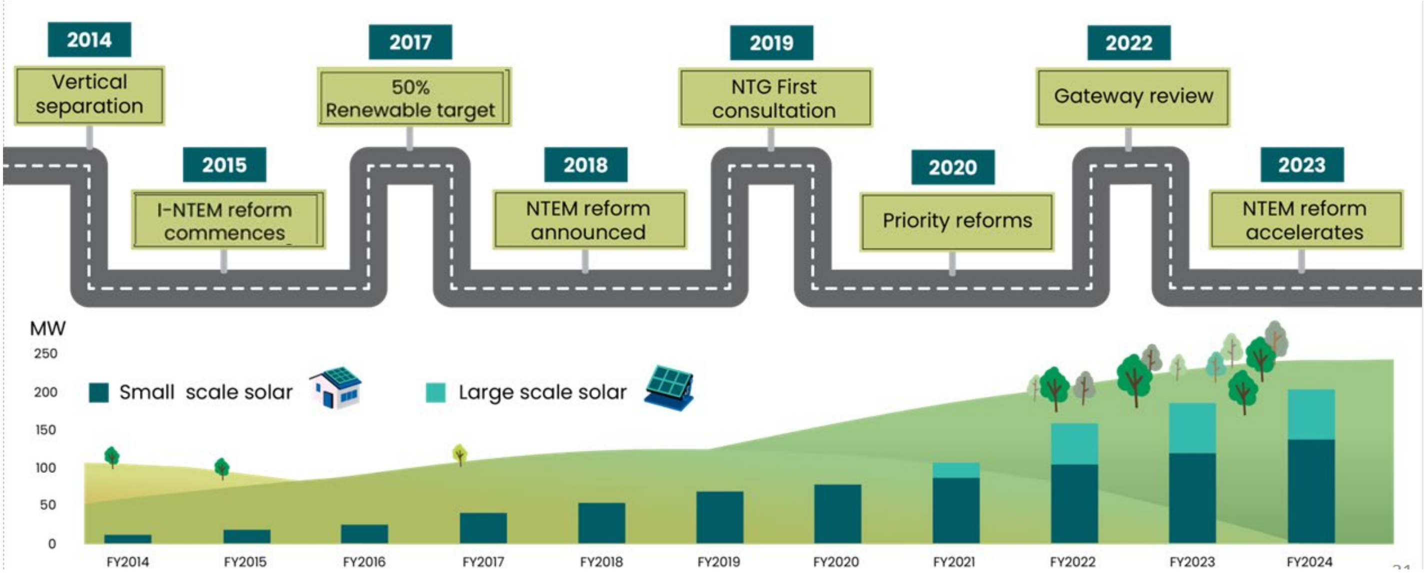
Figure 10 – Drivers of higher costs



In our 2019-24 proposal, we only proposed costs related to our continuing functions under the I-NTEM. While we had expected changes in our circumstances, we expected the NTEM reform process would address the changing landscape and precede the transition. Subsequently we had included a pass through event to recoup our costs of meeting these obligations.

However, the NTEM reform process has been delayed and we have incurred higher costs to meet our changing circumstances without a mechanism for cost recovery under the proposed pass through event. The delay in the NTEM reform process is depicted in **Figure 11**.

Figure 11 – Ongoing journey of NTEM reform



We consider that the additional expenditure was a prudent response in our circumstances. Compared to a counter-factual of staying within our regulated allowance, we consider the following ongoing benefits have been realised for customers in the NT power systems:

- Markedly less power disruptions and outage time for customers, including mitigating risks of major system events.
- Reducing the cost of generation by enabling less conservative dispatch decisions.
- Reducing financial risk to system participants of delayed settlement activity that underpins their power purchase agreements.
- Allowing new generators to enter the market and thereby facilitating the NT Government's 50% RET.
- Ensuring regulatory reform is fit for purpose.

3.1 Power System evolution – transition to renewables

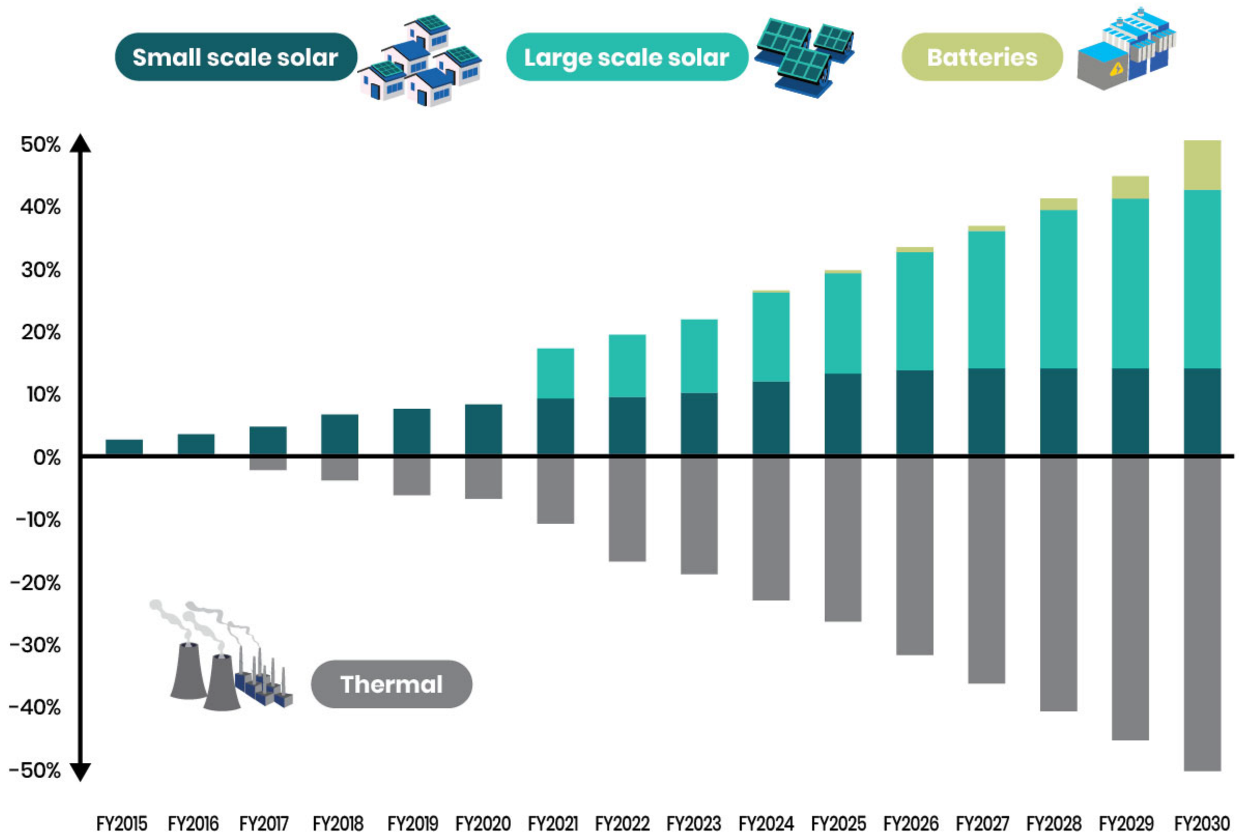
Power systems around the world are responding to climate change by shifting production from high emission generating plant to renewable technologies.

In the NT, the shift commenced a decade ago with households investing in behind the meter PV generating systems. The level of behind the meter PV generating systems has increased over the last 5 years with almost 1 in 5 customers installing behind the meter PV generating systems, with a total capacity of 97 MW, and providing 12% of underlying energy consumption. We are also likely to see a surge in dispatchable large-scale solar in the immediate term, with an expected 55 MW of capacity connecting on the DKIS transmission line.

The NT Government's RET of delivering 50% renewable energy by 2030 has accelerated the transition to renewable technologies in all three power systems. The NT Government's policy objective is to reduce emissions and lower generation costs by substituting synchronous generating plant with renewable sources.

Figure 12 is the NT Government's forecast of growth in renewables as outlined in the 2020 Darwin-Katherine Electricity System Plan. The plan includes continued uptake of behind the meter PV generating systems, connection of large-scale solar farms and battery storage. The plan identifies the retirement of most of the NT's synchronous thermal generators by 2030, as they reach the end of their economic life. Almost half of the existing thermal generation fleet is greater than 35 years old.

Figure 12– NTG Forecasts of energy generation mix by 2030



Facilitating renewables in the NT

The shift from synchronous generating plant to solar production poses considerable challenges for controlling the power system. This includes:

- **Capacity adequacy** - The System Controller must ensure there is sufficient electricity supply scheduled and dispatched to meet demand. Solar only operates in daytime hours when the sun is shining. The System Controller must continue to ensure sufficient capacity is available to meet demand when solar is not being produced.
- **Demand volatility** – Solar production is highly dependent on sunshine. This means there is a surge in demand from synchronous generation when a cloud comes through in the day. The System Controller must plan for these periods by ensuring there is sufficient generation capacity available from non-solar generating plant (synchronous generating plant or energy storage) instantaneously.
- **Essential system services** – Synchronous generation have inherent physical characteristics that can be relied on to provide essential services such as frequency management, voltage support and system strength. These services cannot be relied on to the same extent when renewable energy is predominantly meeting demand in the daytime hours, leading to high risk of system-wide events.

We are already seeing a significant increase in the number of incidents where the system is not secure, and we expect this to grow over time unless we take action.

In the context of the above challenges, System Control plays a critical role in evolving and modernising our tools, systems and processes to schedule and dispatch assets optimally and securely. But we are only part of the equation to ensure a secure and efficient transition to 50% renewable energy by 2030.

We will also require investment in new physical assets including generation plant and battery storage to ensure sufficient capacity to securely meet supply 24 hours a day. We will also require assets that can provide essential system services such as synchronous condensers and grid scale batteries. Changes to the regulatory framework will also play a key role in incentivising sufficient investment in new assets and ensuring the operational rules underlying schedule and dispatch reflect the changing technology mix and characteristics.

Modernising System Control – evolving our processes, tools and systems

Prior to the 2019-24 regulatory period, the System Controller could meet its regulatory obligations with minimal investment in technology and processes. The power systems in our regulated regions were relatively centralised, with generation plant available 24 hours a day and capable of providing essential system services.

Processes

Evaluating the evolving dynamics of the regulated power systems necessitates undertaking detailed complex power system studies. The frequency of the requirement to undertake such studies has increased significantly due to the connection of new facilities and new facility types that have different performance characteristics and capabilities than the legacy generation fleet. As the operating tolerance of the power system diminishes undertaking power system studies is a required element of effective power system management.

Transitional tools

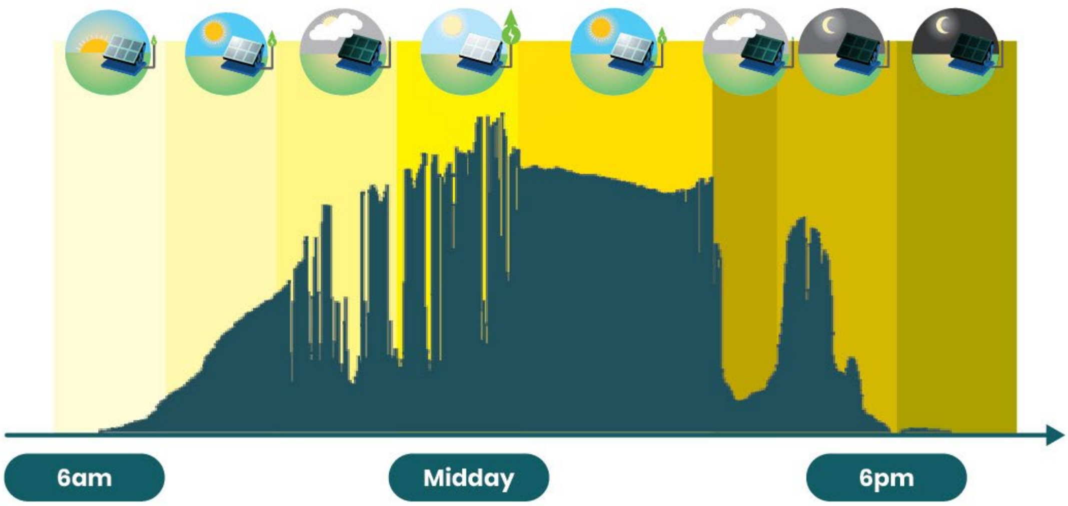
As we transition to renewable energy, the System Controller will need modern real-time systems to access and control the existing and new physical assets on the power system. This reflects the exponential complexity in decision making in an environment where generation technology is diverse, geographically dispersed, larger in number and inherently less predictable and reliable.

Our response to growing renewables on the NT power systems have been proportionate to emerging challenges. This includes developing a suite of transitional tools in the 2019-24 period, plans to evolve and develop new tools to respond to growing renewables, and investing in a new integrated system by the end of the next regulatory period. We discuss each below.

In the 2019-24 period, we developed transitional tools to address challenges with managing a secure power system in light of growing small-scale renewables and connection of large-scale solar farms.

Small scale solar grew significantly in the current regulatory period, supplying an increasing portion of energy demand during the day. However, as seen in **Figure 13**, solar production is highly dependent on sunshine. Cloud cover results in a dip in production, leading to a commensurate surge in demand that must instantaneously be met by non-solar generation. We invested in a transitional tool that provides weather forecasts of the day ahead such that we can plan ahead on how much spinning reserve we require in the system to meet potential surges in demand and to ensure that the power system remains within the secure power system operating envelope. Solar forecasting accuracy is however inherently challenging day ahead.

Figure 13 – Solar production on a day with cloud and sunshine



We have also implemented tools to ensure large-scale generators comply with the Generator Performance Standards (GPS). The GPS applies to all connecting generation facilities above 2 MW to overcome uncertainty in generation performance that could lead to unexpected insecure operation or customer load shedding. We developed a tool that monitored compliance with the minimum capacity forecasts of connected generation. We also developed a tool that enabled us to only dispatch generation in accordance with the minimum capacity forecasts, including where those levels had been reduced as a result of compliance activity.

Evolving transitional tools

Our focus over the next few years is to evolve existing tools to meet the expected connection of large-scale solar farms in DKIS and to manage issues with growing small scale solar.

This includes more granular geographic data on demand forecasts that provide information on cloud cover. This reflects the increasing challenge of managing intermittency of solar as penetration increases, and the geographical spread of solar resources.

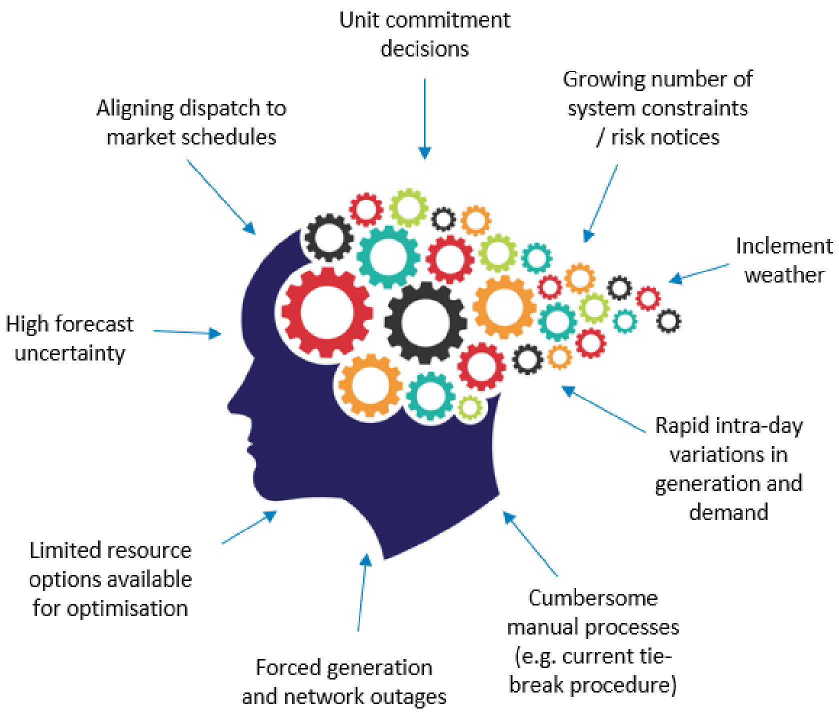
We are also seeing a need to invest in tools that provide greater visibility and response capabilities to ensure adequate essential system services. This reflects that the solar farms on the DKIS line are likely to commence exporting in 2023-24, displacing thermal generation that inherently provided essential system services.

Territory Dispatch Engine

While the transitional tools we have relied on to date have been effective at managing renewable growth, they are not sufficiently integrated or powerful enough to cater for a system that is forecast to be 50% renewable by 2030.

In the next regulatory period, we will likely face a step change in large scale renewable generation and synchronous generation plant retirement. The System Controller will be required to manage a growing set of thermal and non-thermal constraints to optimise a secure and efficient level of dispatch. It is inevitable that the System Controller will need integrated real-time systems to simultaneously manage all the factors impacting the power system. This is depicted in **Figure 14** below.

Figure 14 – Factors contributing to cognitive overload for System Controllers



For this reason we see a need to implement the TDE that is operational by the end of the next regulatory period. The TDE will embed the tools we have developed within an integrated system. The timing of investing in a new system is prudent:

- Increased growth rate of large-scale connection – Consistent with the Darwin-Katherine Electricity System Plan, we are expecting that a significant amount of large-scale generation will connect in the next regulatory period. This is also validated by recent public tenders seeking construction of 100 MW of renewable generation.
- Significant investments in new technology – We also expect that new technologies such as synchronous condensers and grid scale battery energy storage systems will connect to the network in the next regulatory period. Currently, we have limited tools to draw on these physical assets to provide system services such as frequency, voltage and system strength.
- We expect that increased take-up of small scale solar will result in more intervals where there is insufficient demand to enable synchronous generation that secures the system.

3.2 Increasing complexity in meter data for settlement

In 2015, the I-NTEM reform required NTESMO to perform a virtual settlement function in the Darwin-Katherine electricity market. A bespoke Excel spreadsheet was developed to calculate energy consumption and issue virtual invoices to retailers and credit notes to generators. This was intended to be a short-term solution until the NTEM reform provided an understanding of our future compliance obligations. We recognised that a simple Excel spreadsheet would have challenges in accommodating smart meter data and chose a solution that was practical given the policy uncertainty.

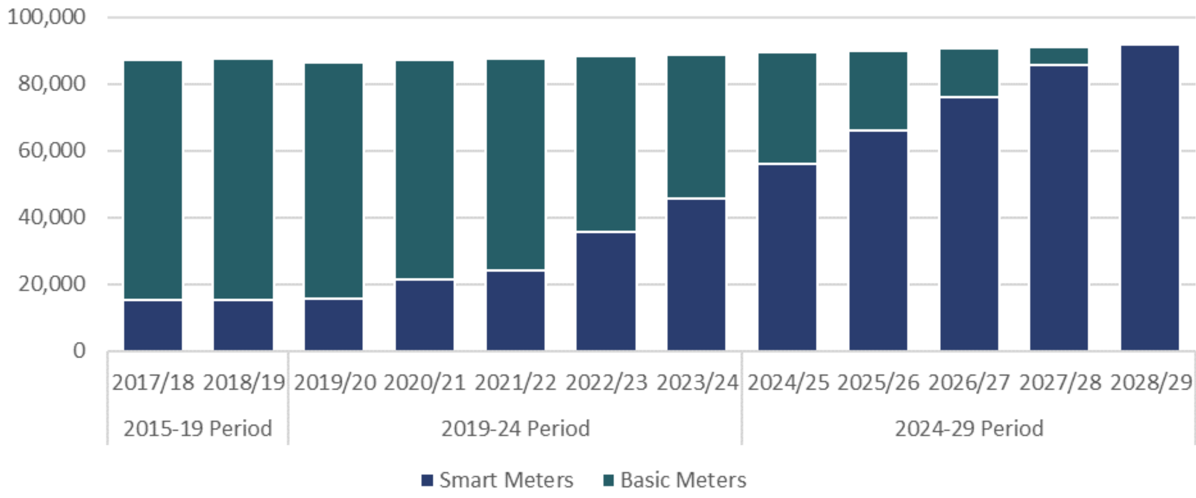
Smart meters provide metering data at 15 minute intervals, as opposed to accumulation meters which are manually read on a quarterly basis. When I-NTEM commenced we only had 1,500 smart meters, a small fraction of the meter population, we now have of 35,918[10] interval meters.

As smart meter penetration grew, we further developed the bespoke Excel spreadsheet to accommodate the increased volume of metering data. This included engaging a vendor to enhance the Excel based system with visual basic scripts to support settlements of up to 19,000 smart meters. At that time, we considered this to be a prudent short-term solution while the specific requirements of NTEM reform were finalised.

Due to NTEM reform delays, we recognised in 2021 that the custom-built Excel spreadsheet was reaching end of life. The key driver was that it could no longer support the expected significant rise in metering data stream inputs, with an expectation that Power and Water will install a smart meter for all connections by 30 June 2029 as seen in **Figure 15**.

[10] Smart meters as at 1 July 2023

Figure 15 – Smart meter roll-out forecasts



Further limitations included:

- It is not inherently secure and was prone to crashing.
- It does not conduct the required validation to support the data processing required to conduct the market settlements and ancillary (essential) services calculations.
- It is unable to support settlements delivery in time due to slow processing, which has resulted in the need for an agreement with some participants that they will receive invoices with incomplete or missing data.
- It does not deliver transparency to customers in the settlement of commercial transactions.
- The customised Excel spreadsheet is unable to be supported by the vendor who developed the visual basic scripts. This is based on a view that the current system was never designed for long term use or with the ability to accommodate further development and is considered inherently risky.

Our business case sought to identify potential options to address the issue including through 'off the shelf' or bespoke settlement systems. Based on a review of vendor offerings, we identified that the best option was an 'off the shelf' solution.

The new Settlements System will reduce the operating time and resource effort of the settlement team through greater automation and integration with the Market Settlement and Transfer Solutions (MSATS) data feeds, better exception management tools and reporting. The personnel savings will partially offset the expected increase in exceptions reporting that is expected with increased smart meter penetration. Similar to the TDE, the system can be configurable to specific requirements arising from NTEM reform.

3.3 Technical advice and rule development

Under the current NT regulatory framework we are the custodian of the SCTC and responsible for reviewing the code, drafting amendments, undertaking stakeholder engagement and proposing amendments for the Commission's approval. This custodian role is unique, with independent rule making bodies in place in other Australian jurisdictions. In the current period this role has included supporting the Generator Performance Standards (GPS) amendments, the current proposed incident reporting amendments, a full review of the SCTC with recommendations provided to the Commission and NT Government. We have also made a number of drafting amendments that have not yet been publicly released, but support alignment with the National Electricity Rules and the NTEM reforms.

In addition to our role as SCTC custodian, we play an important role as technical advisor to the Commission and policy makers within the NT Government. This role is critical, ensuring that the policies developed are fit for purpose in the NT context and can be implemented within our constraints. Historically this has involved attending various working groups and undertaking technical investigations of proposed policy options.

The above activity has been undertaken utilising both our internal personnel and external consultants. This approach is expected to continue into the next regulatory period.

In the 2019-24 determination, we were unable to incorporate ‘speculative costs’ associated with policy and rule development prior to the new obligation being approved. It was anticipated that these costs would be recovered when the NTEM reforms associated with this activity were approved. This has not occurred and as such we are seeking to recover a portion of the historical costs.

4. Listening to our stakeholders

We consulted extensively with major customers and system participants on key issues impacting this Regulatory Proposal. Our stakeholders recognised that NTESMO needs to respond to changes in the external environment, but wanted to ensure that expenditure was efficient and justified. Our Regulatory Proposal has responded to stakeholder positions by balancing the need to minimise bill impacts while incurring prudent expenditure that ensures the security of the NT power systems.

NTESMO's services and regulated charges are important issues for our customers and market participants. For this reason, we sought stakeholder feedback when developing this proposal through a series of consultations on key issues. In this Chapter we outline how we engaged with stakeholders, and how we responded to their feedback.

4.1 Method and approach to engagement

We recognise that stakeholder feedback is an evolving facet of regulatory proposals. Our engagement focused on major customers that are not subject to the protections of the NT Electricity Pricing Order, together with key system participants that rely on NTESMO's services such as generators and retailers.

We undertook two rounds of consultation in May and August 2023. In each round, we published a consultation paper on our website seeking written feedback from stakeholders. We also held two stakeholder workshops for major customers and stakeholders to complement our consultation paper. Finally, we sought 'one on one' sessions with major customers and system participants that were not able to attend the workshops.

Attachment 4.1 provides details on how we have engaged, and the feedback received from stakeholders through written submissions, and through our workshops and 'one on one' sessions for each consultation round. Overall we are thankful for the contributions and time of our stakeholders, and we have sought to respond to the feedback provided.

4.2 First round of consultation

We published a consultation paper on 17 May 2023 to commence the first round of consultation. We described the key challenges impacting the operation of the power system and our role as System Control and Market Operator. This included managing our transition to a renewable energy system and meeting our compliance obligations to settle the market. We also set out key issues with the framework for the next regulatory proposal including the structure of the regulatory proposal, mechanisms to manage uncertainty in the reform process, and changes in our charging structures.

We convened a workshop on 30 May 2023 to talk through key issues outlined in the consultation paper, and gather feedback from our stakeholders. We received valuable feedback on the day, which was then used to develop our second consultation paper. NTESMO also met with a number of stakeholders in one-on-one meetings, particularly stakeholders who could not attend the workshop. Two written submissions were received from the Northern Territory Chamber of Commerce and Rimfire in response to the issues in the consultation paper. Below we provide a summary of feedback received.

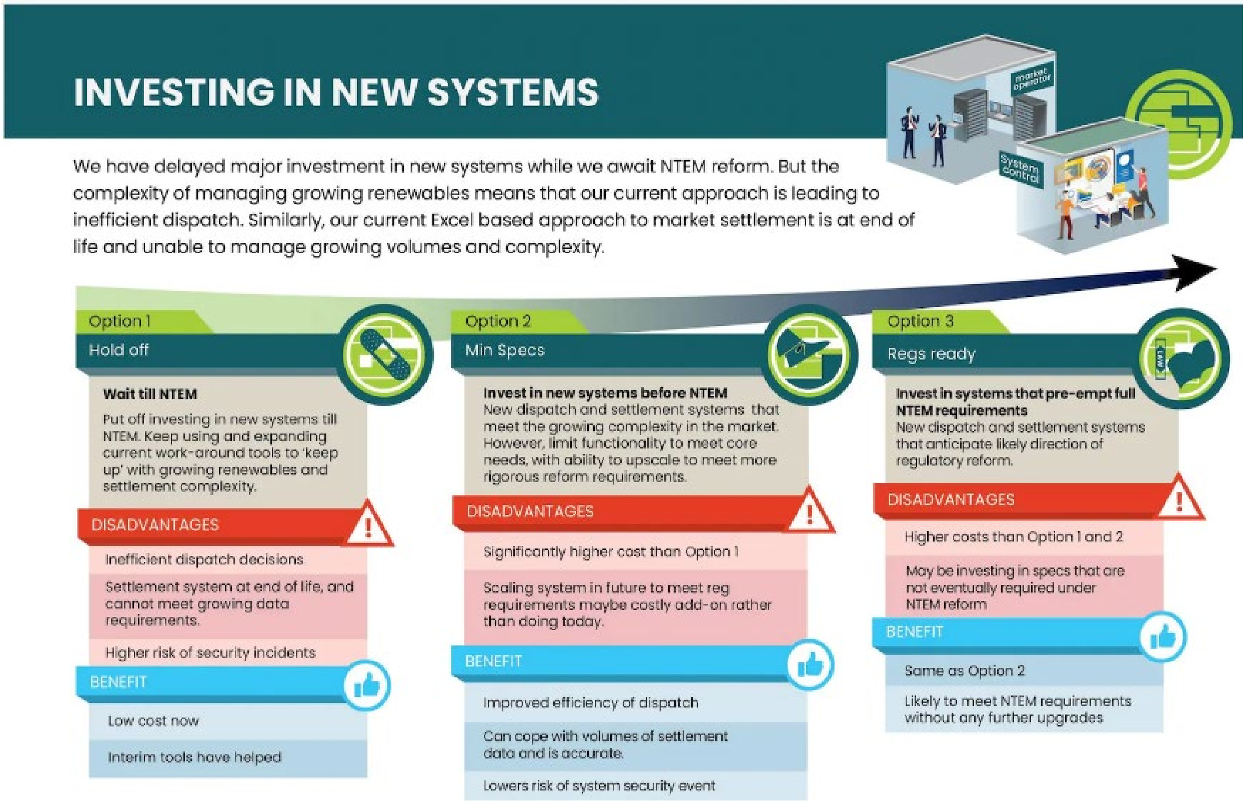
Responding to changes in the NT Electricity System

Through this first round of consultation we identified the rapid changes impacting the NT power systems including the transition to 50% renewable energy by 2030. In the workshop, during one on one sessions and in written submissions, stakeholders acknowledged the pace of change across the NT power systems and the impact that is having on NTESMO.

At the first workshop, stakeholders expressed a sentiment to 'get on with it' acknowledging the need for response and action. However, stakeholders noted that we should 'be mindful of costs', emphasising the need for robust cost benefit analysis to support investment options. Finally, stakeholders considered we should 'be conscious of impacts' in working through who and how transition costs are recovered.

In the workshop, we sought feedback on the direction of current and future major investments, including the implementation of the new Settlements System and development of the TDE. During the workshop we discussed the investment options available which are depicted in **Figure 16**:

Figure 16 - Investment options discussed with stakeholders



Most stakeholders identified a preference for an investment profile between Option 2 (Minimum) and Option 3 (Regulation ready). In our qualitative discussion, stakeholders noted the high risks of holding off key investments, and considered that our systems should be adaptable to changes in regulations without necessarily anticipating the requirements.

In its written submission, the Northern Territory Chamber of Commerce were appreciative of the fact that NTESMO was proactive in managing the complex challenges presented by the transition to renewables, data complexity and uncertainty of NTEM reform. It also noted that given the potential exposure to the high cost of system failure, the proposed investment into the TDE seemed sensible and timely.

Based on this feedback, we considered there was qualified support for NTESMO to make key investments ahead of the finalisation of the NTEM reform provided that there is sufficient business case justification and that investments were adaptable to future reform.

Feedback on framework issues

We also raised other issues for feedback including the optimal length of the regulatory period, how to address uncertainty in scope and timing of NTEM reform, and changes in the structure of our charges. Finally, we noted that due to time delays we would submit an annual pricing proposal for the 2024-25 period to the Commission in September 2023, which would reflect the approved 2023-24 prices with an adjustment for inflation. While this would set prices for the first year of the next regulatory period, a comprehensive proposal would be submitted in December 2023 using a building blocks approach to required revenue from 2024-25 through to 2026-27.

In general, the feedback received at the stakeholder workshop, one on one sessions and through written submissions was diverse:

- Shorter regulatory period – At the industry workshop, several stakeholders preferred a three-year period to enable a flexible response to NTEM reform and broader market uncertainties. However, there was also support from other stakeholders for retaining the current five-year period to limit administrative burden, noting that other mechanisms could be used to manage uncertainty around the finalisation of the NTEM reform. In its written submission, Rimfire suggested that a longer regulatory period may be preferable as it provides greater certainty of charges for retailers/customers and revenue for NTESMO.
- Two proposal process – In the workshop and one on one sessions, stakeholders generally recognised that the delay in the timing of our Regulatory Proposal would necessitate the need for a simple roll forward of prices in the first year of the regulatory period.
- Mechanisms to manage uncertainty – In the workshop and one on one sessions, the majority of stakeholders agreed that cost recovery for NTEM reform and new obligations should be available in the regulatory period through appropriate mechanisms but sought information on practical examples.
- Changes in charging structures – Currently we levy charges on the retailer based on the level of consumption of their customer. In the workshop and one on one sessions, stakeholders did not express a strong view on whether the current arrangements should be changed, for instance by charging generators a portion of the levy or through the introduction of fixed charges. In its written submission, Rimfire supported retaining the current approach of cost recovery on a usage (kWh) basis and recoverable through retailers.

Based on these views, we developed positions for the Framework and Approach paper as part of the second round of consultation. We considered that stakeholders had broadly agreed with a framework that managed uncertainty with the pace of change through shorter regulatory periods, mechanisms for within-period adjustments, and minimal changes to charging structures allowing for more considered reflection as part of the following determination process.

4.3 Second round of consultation

Our second round of consultation commenced with a stakeholder workshop held on 22 August 2023, followed by the publication of our second consultation paper on 23 August 2023. Similar to the first round of consultation, we also held a number of one on one meetings with those who were not able to attend the forum. We also sought written feedback from stakeholders on the issues raised in the consultation paper.

The key issues discussed in the second round of consultations included our preferred positions for the regulatory framework and approach, the principles to apply to the inclusion of costs that exceeded our allowance, and whether we should seek to defer retrospective cost recovery to future periods. We discuss stakeholder feedback and our response in the sections below which was garnered from the industry workshop, one on one sessions, and written submissions from Jacana Energy, TGen, the Manufacturers Council and EDL Energy.

Preferred positions for framework and approach

Through our second consultation process, we sought feedback on our preferred positions for the framework and approach for the next regulatory period. This included our intention to roll forward prices by CPI for 2024-25, while submitting a shorter three-year period from 2024-25 to 2026-27 in December 2023. We also identified that we would seek to include two mechanisms for uncertainty similar to those available in the National Electricity Rules framework. Finally, we sought feedback on our position to maintain the current approach to the structure of charges and billing the retailer.

In the workshop and one on one sessions, the majority of stakeholders agreed with the preferred positions we had outlined, seeing this as a practical approach given the degree of uncertainty and the need to keep the regulatory framework simple.

The written submissions generally supported the framework and approach positions outlined in the second consultation paper. In particular:

- The Manufacturer's Council noted that a shorter period is preferred on the basis that 5 years does not allow for the variation in operational costs and new technology uptake.
- EDL did not consider there was any reason to depart from the positions put forward in our consultation paper.
- Jacana Energy considered that the preferred position to maintain the current approach to charging structures provides transparency to customers. It noted that alternative arrangements to recover payments from generators would not serve any benefit to customers, as generators would ultimately pass on these costs.

Based on the positive feedback for the preferred positions, this Regulatory Proposal has embedded the positions set out in Chapter 2.

Principles to apply for retrospective cost recovery

Through our second phase of consultation we noted a significant increase in the regulated charges for the next regulatory period based on our initial calculation of charge. In explaining the key drivers of higher costs in the current period, we sought to test with stakeholders key principles we could use to underpin our decision to include or exclude specific current period costs from the proposal. The four principles included:

1. ensuring there is no double counting expenditure
2. only seeking expenditure which is prudent
3. only seeking expenditure which is efficient

4. only seeking expenditure which was not foreseeable at the time the 2019 NTESMO proposal was prepared.

At both the workshop and one on one sessions, there was broad support for all principles, with particularly strong support for the principle of no double counting. At these sessions, we queried our stakeholders on whether anything was missing from the principles, or whether additional principles should be considered, stakeholder suggestions included frugality, expanding the efficient principle to include effective and economic, and cost benefit.

At our stakeholder workshop, we had sessions on each specific retrospective cost item. The key messages were as follows:

- Power System evolution - Stakeholders broadly supported NTESMO acting on renewables. The general view was that there is 'no option to not prepare for the future of renewables'. Stakeholders considered further justification should be provided on the economic justification including the cost benefit analysis, and information on what projects were prioritised.
- Settlements Systems - Stakeholders strongly supported NTESMO investing in a new Settlements System. It was generally considered that that 'risk of not being able to settle is too great'. Stakeholders sought further information to show that specifications were not excessive, and information on the choices we had in front of us in making the decision.
- Rule changes and NTEM reform - The general view of stakeholders appeared to be that NTESMO is appropriate for this role as 'the electricity system is very complex' and 'NTESMO has the subject matter expertise'. Stakeholders sought more information on the advice we had provided and demonstration that costs had been allocated correctly.
- Corporate costs - There was modest support for NTESMO seeking additional revenue for corporate costs. The general view appeared to be that 'all businesses have operating processes that are dependent on corporate services being provided'. Stakeholders sought clarity on the allocation process and the overall level of corporate costs.

Written submissions also provided views on retrospective cost recovery and the principles we should adopt:

- The Manufacturer's Council indicated a need to increase pricing for electricity for the NT grid and that the stability of the grid is paramount. It noted that the inclusion of renewables reflects an enormous cost to ensure essential stable grid operations. The Council was of the view that additional funding should be sought from Governments to meet the higher costs, rather than be borne by customers.
- EDL considered it appropriate that NTESMO expected the NTEM reform to facilitate a pass through of costs, where those costs where increased by reasonably unforeseeable changes in the NT power systems. Considering that the NTEM reform has not provided certainty within the period, EDL considered it fair that certain costs be recoverable. However, EDL noted the need for independent review of the necessity of the recovery amount.
- Jacana Energy considered that retrospective cost recovery should not be borne by customers given the drivers of these costs were, in their view, foreseeable and should have been factored into previous proposals. Jacana Energy was concerned on the significant increase in costs, and considered there was a growing misalignment of costs comparative to other jurisdictions. It considered that the cost drivers do not adequately meet the principles proposed by NTESMO for cost recovery, and that NTESMO has not adequately defined the benefits for customers. Nevertheless, Jacana did note that a principle that could be applied related to whether the expenditure was related to meeting a Community Service Obligation in respect of implementing government social policy.

- TGen considered that the increase in regulated charges cannot be justified by regulatory means, especially considering the basis for such a move and imposes an unfair burden on current market participants. In this respect, it questioned the fairness of why new system participants should pay for previous costs incurred. While it did not dispute that operation costs have increased, including for NTESMO, it considered that the budget situation in the Territory is tight.

We have deeply considered the views of stakeholders on the issue of retrospective cost recovery. In general, we see that stakeholders recognised a need to incur higher expenditure to meet our functions and assist the NT's transition to renewable energy. However stakeholders expressed a need to minimise bill impacts that may occur in seeking retrospective costs.

As discussed in Chapter 7 of this Regulatory Proposal, we have only sought retrospective recovery of a subset of costs that were above the Commission's allowance in 2019-24. We have not included corporate costs and personnel costs above the allowance on the logic that these were to a degree foreseeable at the time of our proposal. However, we consider that expenditure on the power system evolution, Settlements System and Rule changes and NTEM reform met the principles. In our detailed justification documents and business case summaries, we have provided the additional information requested by stakeholders for the dot points above.

Options to defer recovery to minimise bill impacts

In our consultation paper, we had noted that one means of reducing bill impacts to customers was to defer a portion of the retrospective costs to future regulatory periods. In the workshop, stakeholders supported the concept of revenue deferral, but there was no clear consensus between Option 2 (50% deferral) and Option 3 (75% deferral).

Jacana Energy was the only written submission that put forward a view on deferral of revenue. Jacana Energy noted that while it was of the view that retrospective costs should not be recovered from customers, it supported a longer recovery period to reduce the impact on customers. Jacana Energy had no specific amount in mind but noted that the term of recovery should equate to the expected years of benefit.

We have taken this feedback into account in proposing a deferral of 50% of retrospective costs. We consider that a lower deferral amount is appropriate given that we have only proposed to recover a subset of our retrospective costs.

We have also considered other mechanisms that would give effect to the principle of minimising price impacts. As noted in Chapter 2, we have adopted a pragmatic approach to capitalisation that balances customer price outcomes with accounting standards. Under this approach, we re-categorised expenditure on assets from opex to capex. This was based on determining costs that related to the development and implementation of an asset that provides a service for longer than a year including transitional tools, development of the Settlements System business case, and development of the TDE RBC.

The approach is in line with stakeholder feedback, which indicated a preference for deferring revenue recovery to minimise customer price shock. If a more conservative approach is adopted and these costs were treated as opex, these costs would be recovered in the year incurred. This would result in larger price increases than already forecast.

5. Operating expenditure

Opex increased significantly in the current period as we responded to external changes in the NT electricity system and market. We are proposing a total NTESMO opex of $57.8 million in the next regulatory period. This reflects the need to increase staff levels, perform our role as the SCTC custodian, and to provide technical advice to policy makers including on the NTEM reform.

Opex relates to costs on non-asset related activities. Opex is recovered on an annual basis. The purpose of this chapter is to set out our forecast opex for the next regulatory period. We identify changes in our actual and forecast opex in the current 2019-24 regulatory period. Chapter 7 of this Regulatory Proposal provides further detail on the costs incurred in the current period that we seek to retrospectively recover in the next regulatory period. Please note that all numbers are presented in real 2023-24 dollars.

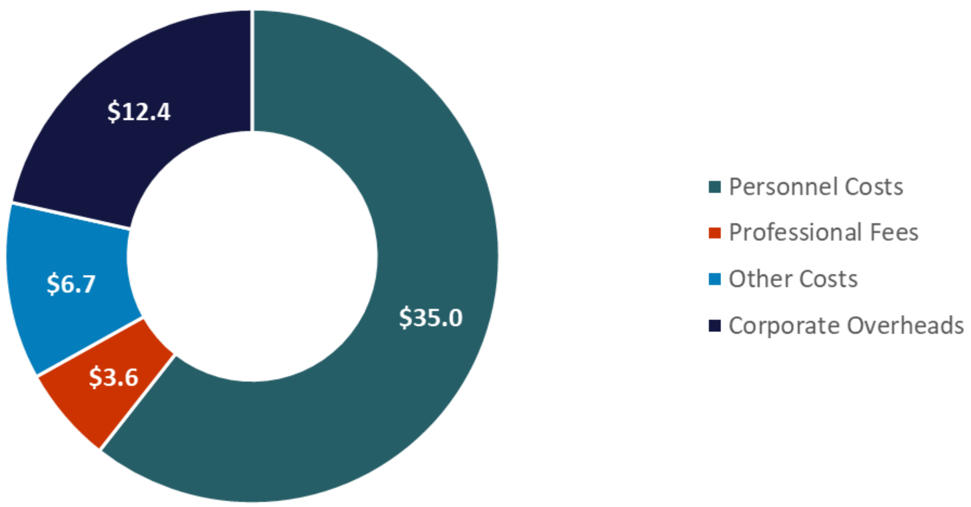
5.1 Overview of forecast opex

In aggregate we forecast that System Control and Market Operator will incur $57.8 million opex over the 2024-27 regulatory period, or approximately $19.3 million per annum.

Opex by cost category

Figure 17 shows that personnel and overheads are the dominant opex categories in the next regulatory period in aggregate for System Control and Market Operator. Personnel costs are about $35.0 million, comprising 60.6% of proposed opex. The portion of Power and Water's corporate overheads allocated to NTESMO is forecast at $12.4 million, or about 21.5% of proposed opex.

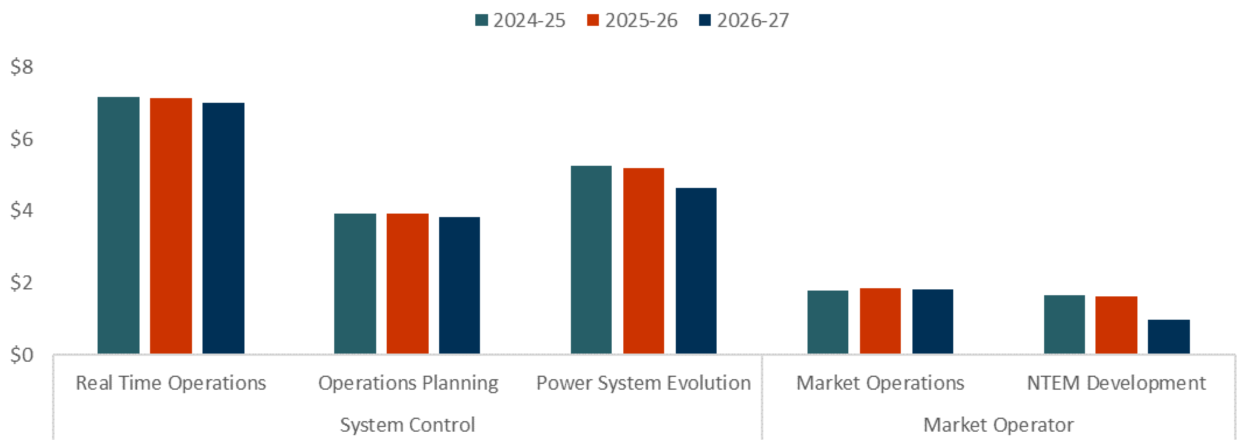
Figure 17 – Forecast opex by cost category ($m, real 2023-24)



Opex by function

Figure 18 below shows that System Control comprises the majority of proposed opex at 83.2%. The System Control function of power system evolution and real time operations together comprise 63.0% of proposed opex.

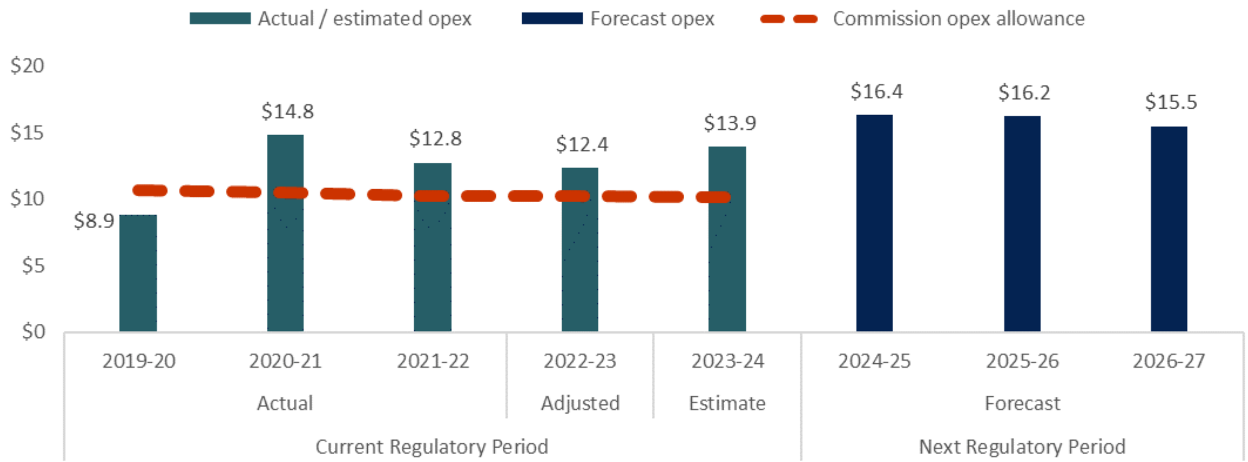
Figure 18 – Forecast opex by Function and service ($m real, 2023-24)



System Control trend opex

As can be seen in **Figure 19** below, System Control opex increased over the current period, and peaks in the first year of the next regulatory period. We have incurred higher costs than the approved allowance primarily due to increased personnel needed to meet the challenges of growing renewables on the NT power systems. This increase primarily required more engineering capability along with additional support for the control room. Other reasons for higher opex relate to improved incident reporting capabilities, improved compliance practices and higher corporate overheads than forecast at the time of our 2019-24 regulatory proposal.

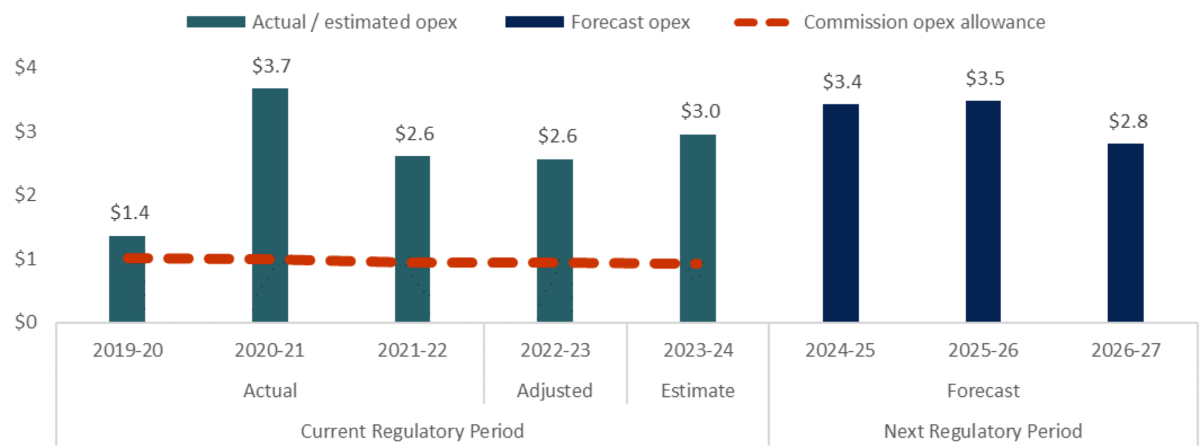
Figure 19 – System control actual and forecast opex ($m, real 2023-24)



Market Operator opex trend

Figure 20 shows that Market Operator opex increased markedly in 2020-21 but stabilises from 2022-23 through to the next regulatory period, with slightly higher opex in 2024-25. Market Operator opex has also increased compared to the Commission's 2019-24 allowance. There are two key drivers, the first relates to increases in personnel costs to provide advice and drafting support for NTEM reforms, and the second relates to the ongoing software provision and support costs for the new Settlements System discussed in Chapter 6. A further driver of increased opex relates to higher corporate overheads than forecast at the time of our 2019-24 regulatory proposal.

Figure 20 – Market Operator actual and forecast opex ($m, real 2023-24)



5.2 Method to forecast opex

We have forecast opex for System Control and Market Operator functions by cost category including personnel, professional fees, corporate overheads, and residual costs. Our method to derive category specific forecasts are described below. Further detail on our forecasting methodology is provided in **Attachment 5.2**.

Mapping actual expenditure

The first step was to ensure that actual costs between 2019-20 and 2022-23 in our General Ledger had been mapped to the appropriate service within System Control and Market Operator. During the current regulatory period, Power and Water implemented structural reform, which included the creation of the Core Operation business unit. This impacted the General Ledger structure and as such some mapping was required to ensure all costs were captured. The changes also require an allocation of central Core Operations costs to the NTESMO functions[11].

When remapping the general ledger, it became apparent that a new service was required within the System Control function to capture costs related to the power system evolution. This category captured the costs associated with system, process and regulatory changes to support the modernisation of the power system. In the General Ledger, costs associated with this function had initially been allocated to NTEM reform. Upon further reflection, the costs relating to facilitating renewables across the three regulated regions relate to the functions of the System Controller under the SCTC.

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11 See discussion in Chapter 2.4 and Attachment 2.2

We also adjusted the General Ledger to exclude costs that provide ongoing (beyond one year) benefit to our customers, which have been allocated to capex. This included the professional services costs relating to the development and implementation of transitional tools, Settlements System and the TDE. These costs are discussed in Chapter 6 and **Attachment 5.2** provides further detail on the approach to capitalisation.

5.3 Personnel costs

Personnel costs include the labour costs of employees and contractors[12] allocated to System Control and Market Operator. We have combined both NTESMO operational personnel costs, along with capitalised personnel costs, to identify a total personnel budget requirement.

We forecast personnel costs by identifying the activities performed by each staff member in the 2022-23 base year and allocating a percentage to each activity. This provided a means of identifying the percentage of work dedicated to both regulated and unregulated activities which is applied to the total personnel cost. The outcome was to identify the labour costs incurred in 2022-23 by function and activity performed. This is provided at **Attachment 5.1**.

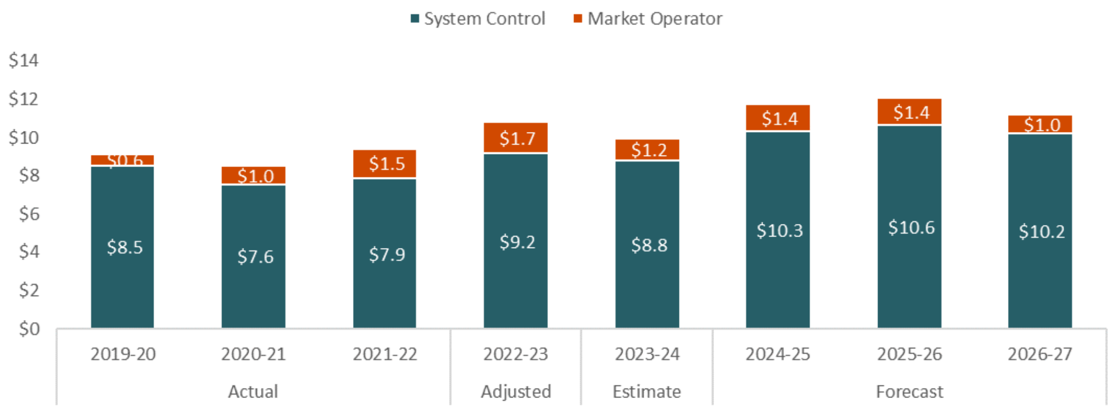
Our step change method included a forecast increase in employees from the creation of new positions along with a reduction in the abnormally high vacancy rate that was experienced in 2022-23.

We applied the activity mapping method described above to the additional personnel costs to enable us to understand the activity being performed and to exclude personnel costs related to unregulated activities and anticipated functions under NTEM reform that are not current obligations. In our step change calculation, we also excluded personnel costs where the activity related to a forecast capex program such as development of the TDE. The proposed step change consequently only relates to the additional positions required to meet our current opex regulatory obligations. We allocate a portion of the personnel costs to capitalised projects as identified in Chapter 6.

The last step was to adjust labour costs to reflect the recently approved 2021-2026 Power and Water Enterprise Agreement (Power and Water EA). This included a significant increase in costs in 2023-24 due to backdating of the Power and Water EA.

As seen in **Figure 21**, personnel costs have increased over the regulatory period, and are forecast to increase further in the next regulatory period for both System Control and Market Operator.

Figure 21 – Personnel costs ($m, real 2023-24)



12 Contractors are primarily undergraduates or new graduates.

Changes from 2019-24 determination

The key drivers for the increased personnel costs relate to increased engineering support requirements and control room support and resilience.

Engineering

In the 2019-24 determination 12 engineering positions were included, we currently have 32 approved engineering positions across both regulated and non-regulated NTESMO activity. This increase represents a significant portion of the personnel cost increase and has been driven by:

- increased risk notification processing
- improved incident reporting capabilities including timely reporting
- ongoing maintenance and operation of the dynamic system modelling
- increased generator connection processing (System Control obligation components)
- additional control room support and training
- improved demand forecasting capabilities
- advisory role for NT Government on reforms across the NT power systems
- implementing undergraduate/graduate engineering programs due to lack of available skilled resources
- interim ad hoc system planning in the absence of progress of NTEM reforms
- additional demand forecasting capabilities and support.

Control room

The 2019-24 determination included a reduction in the number of real time operations full time equivalent staff (FTE) from 28 to 22 and included an additional 3 support staff, bringing the total real time staff to 25 FTE. Currently we have 28 approved real time operations positions, with an additional 8 support staff, bringing the total to 36 FTE. This increase has been driven by:

- power system complexity requiring additional technical support for the control room
- new tools and processes requiring controllers to be offline to undertake training, and
- continuation of transitioning key control room staff to retirement.

Further detail for both the control room and engineering resource increases is provided in **Attachment 5.2**.

Step changes

Vacancy rate adjustment

During 2022-23, NTESMO experienced recruitment challenges that resulted in a higher than normal vacancy rate of 18% (average over the year). This vacancy rate is not forecast to continue into the next regulatory period and as such the personnel costs have been adjusted to reflect a vacancy rate of 5%.

The key improvements made are:

- recruitment to the Senior Manager Electricity Market and Reform position
- partnership arrangements with Charles Darwin University that enhanced our success and workforce planning strategies, mitigating skills shortages and addressing future labour needs more proactively
- alternative advertising and sourcing arrangements for controllers

Table 5 provides a summary of the percentage and dollar value of the vacancy adjustment by function.

Table 5 – Vacancy rate adjustment ($m, 2023-24)

	%	$000
Vacancy Rate	18%	2,067

New positions

The majority of new positions in the next regulatory period are required in the area of Power System Evolution. These positions will support the continued evolution of tools to manage the further acceleration of renewables on the power system, including a step change in large scale renewable generation. Additional positions are also required to provide the necessary subject matter expertise to the NT Government as it seeks to progress the NTEM reforms over the next regulatory period. **Table 6** provides the total costs associated with the new positions required.

Table 6 – Personnel costs arising from new positions ($m, real 2023-24)

	2024-25	2025-26	2026-27
New Positions	1.2	1.1	0.2

Undergraduate and graduate contract arrangements

Similar to the broader utilities industry both in Australia and internationally, NTESMO is experiencing significant resourcing constraints. This has led to the establishment of two programs with Charles Darwin University for the provision of Undergraduate and Graduate Engineers. These programs, tailored for engineering roles within NTESMO, are critical for effective succession planning as it enables the systematic development and nurturing of a pipeline of engineering talent, ensuring a continuous supply of qualified professionals to fill critical roles as experienced employees retire or advance.

Additionally, these programs allow for the inculcation of industry-specific knowledge and practices, equipping graduates with the skills needed to navigate the complexity of the System Control functions. Moreover, they serve as a platform for knowledge transfer, enabling senior engineers to mentor and pass on their expertise to the next generation, ensuring the preservation of institutional knowledge. Ultimately, this strategic investment in talent development not only safeguards the continuity and stability of System Control services but also fosters innovation and adaptability to meet the evolving challenges in the NT power systems. **Table 7** provides the total costs associated with the additional graduate contract costs.

Table 7 – Graduate Contract Arrangement costs ($m, real 2023-24)

$ Real 2022-23	2024-25	2025-26	2026-27
Graduate/Undergraduate Contract	0.4	0.4	0.4

Total personnel costs

A percentage of the total personnel expenditure is capitalised, representing the internal effort associated with capital projects, thereby reducing the personnel opex cost forecast. **Table 8** provides a summary of the personnel costs to be forecast in opex, capex and totex.

Table 8 – Total personnel costs ($m, real 2023-24)

$ Real 2022-23	2024-25	2025-26	2026-27
Capex	2.0	1.7	1.5
Opex	11.2	11.4	10.6
Totex	13.2	13.1	12.1

Escalation rates

There are three separate agreements under which escalation rates are governed:

- executive contract employees (Northern Territory Public Sector 2021-2025 Enterprise Agreement)
- non-executive contract employees (Power and Water EA)
- contracted graduates and undergraduates (external contract escalated by CPI).

Consideration was initially given to utilising the BIS Oxford 19 September 2023 - EGWWS WPI NT as the escalation rate for personnel. However, with the finalisation and commencement of new enterprise agreements applicable to staff in July 2023, it is now appropriate to consider the actual escalations provided in these Agreements.

Noting the different escalation rates that apply to personnel in NTESMO, we have applied a weighted average escalation rate to personnel costs, considering the two years of escalation for 2021-2022 which was accounted for in the FY23 General Ledger by way of a journal.

In addition to the underlying enterprise agreement escalations, an additional escalation for the Australian Government superannuation contribution changes has been included. **Table 9** provides a summary of the various escalation rates, and the weighted average applied in our proposal.

Table 9 – Escalation rates and weighted average escalation applied in the proposal

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Executive Contract			2.00%	2.00%	2.00%	2.00%
Non-Executive Contract	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Graduate/Undergraduates			3.60%	2.80%	2.80%	2.80%
Weighted Average	2.44%	2.44%	2.88%	2.85%	2.85%	2.85%
As applied in model			**7.97%**	**2.85%**	**2.85%**	**2.85%**
Superannuation rate increase			**0.50%**	**0.50%**	**0.50%**	

*8.00% is the cumulative weighted average increase for 2021-23

5.4 Professional fees

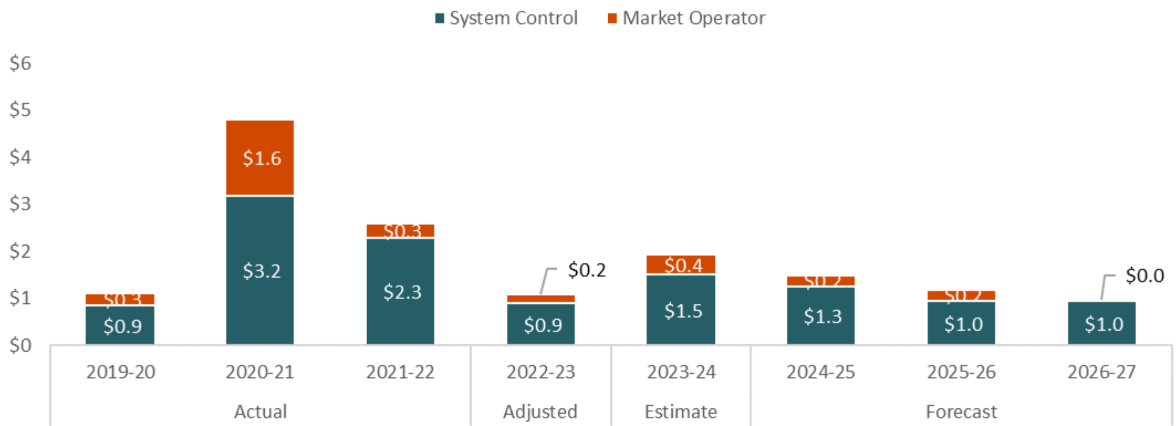
Professional fees relate to payments to external parties to procure technical advice and services that are not provided by internal personnel. Professional fees for assets such as transitional tools have been re-allocated to capex for the purposes of this Regulatory Proposal and are described in Chapter 6. The professional fees allocated to opex only include payments for non-asset related activities.

Our forecast approach involved adjusting the 2022-23 base year to remove professional fees related to specific one-off projects that were unlikely to be recurrent. This included transitional tool research and development, NTEM reform, enhanced capability and SCTC reviews that have significant variation from year to year. The adjusted 2022-23 base year only included ‘business as usual’ professional fees, which totalled $0.8 million. This was on the basis that these costs stay relatively stable on a ‘year to year’ basis.

Our next step was to forecast changes from the adjusted base year. This involved forecasting professional fees for specific projects excluded from the base year including transitional tool support, NTEM reform, SCTC reviews, and enhanced capability.

Figure 22 shows the trend in actual, estimated and forecast opex for professional fees. The volatility reflects that professional fees vary based on the project or driver.

Figure 22 – Professional fees ($m, real 2023-24)



Step changes

The adjusted base year only includes the business-as-usual type professional fees of $0.8 million a year. Going forward, we are forecasting specific project costs related to:

- Advice to policy makers including NTEM reform.
- A mandated review of the SCTC, which is likely to take place in 2025.
- Enhanced capability projects which include procedure and process changes, an interim System Security Investment Plan, a Managing Renewables Integration Strategy, and web page content updates.

Attachment 5.2 provides further detail on the step changes, of particular note is the limitations on the forecast for policy design advice and rule changes. The attachment outlines what is included and what would trigger a cost pass through.

Table 10 summarises the professional fees step change.

Table 10 – Professional fees step change ($m, real 2023-24)

$ Real 2022-23	2024-25	2025-26	2026-27
Step Change	0.7	0.4	0.2

Total professional fees

Table 11 details the total professional fees forecast:

Table 11 – Total professional fees forecast in this Regulatory Proposal ($m, real 2024)

$ Real 2022-23	2024-25	2025-26	2026-27
Total Professional Fees	1.5	1.2	1.0

5.5 Corporate overheads

NTESMO operates within the Core Operations business unit at Power and Water. Corporate overheads are shared costs within Power and Water that are not wholly and exclusively associated with a single business unit. We allocate overheads to each line of business in accordance with our AER approved CAM. This is based on using an appropriate causal allocator. Corporate overheads are then either expensed or capitalised based on an accounting method applied and approved in the current AER determination.

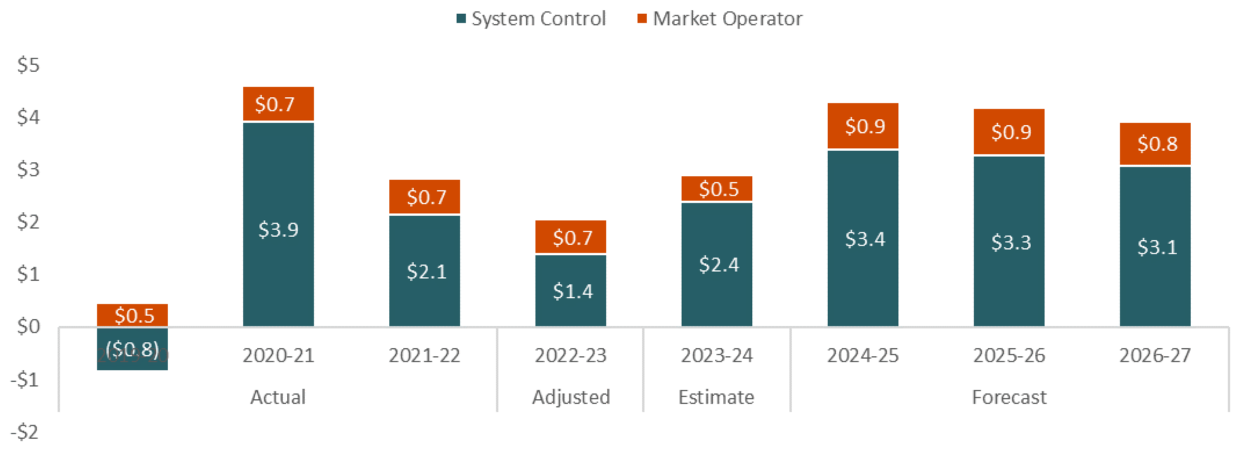
We have applied the AER's approved CAM to allocate corporate overheads to Core Operations. We have then used the principles of the approved CAM to allocate these costs to the System Control and Market Operator functions within Core Operations[13]. We have applied this approach to forecast and historical corporate overheads. **Attachment 2.2** provides further detail on the CAM application within Core Operations. The AER approved CAM is provided at **Attachment 2.1**.

We believe the activity allocation methodology we have applied reasonably reflects the costs of undertaking a set of related activities to provide support services to market operator and system control activities to achieve forecast objectives.

Figure 23 shows the trend of corporate overheads that have been expensed. We note that Chapter 6 includes the corporate overheads that have been capitalised. The key driver of higher corporate overheads relates to transformation activities within Power and Water, and an increase in personnel in NTESMO functions which is a causal driver for many corporate services.

[13] See discussion at Chapter 2.4 and Attachment 2.3

Figure 23 – Corporate overheads ($m, real 2023-24)



Changes from 2019-24 determination

Corporate overheads have increased since the 2019-24 determination, which has been driven by both an increased allocation to NTESMO and an increase in overall corporate costs. The increased allocation to NTESMO has been driven by NTESMO's increasing FTEs, which is the primary allocation driver.

The overall increase relates to a number of initiatives, the most significant being Our New Operating Model program, which includes a program of work to implement integrated ICT solutions to manage work across Power and Water's core capabilities. Within the current regulatory period this has included the delivery of a meter to cash system and a health, environment, risk, compliance and safety system. The overhead costs of running the significant program have been recovered through the Corporate OH allocations and will continue to be into the next regulatory period. This program is vital as the majority of Power and Water's core systems are near end-of-life.

Forecast corporate overhead costs

Corporate overheads are expected to continue to remain higher in the next regulatory period, although declining in real terms.

It is expected that increased cyber security requirements driven by legislative change, a transition to cloud based platforms and an increase in insurance costs will also contribute to higher corporate overheads continuing into the next period.

We adopt a similar approach to that of personnel, where a portion of corporate overheads is capitalised. This is consistent with the approach adopted for the AER. The percentage of corporate overhead costs associated with capital projects is capitalised, thereby reducing the corporate overhead opex forecast. **Table 12** provides a summary of the corporate overhead costs forecast in opex, capex and totex.

Table 12 – Corporate overhead costs ($m, real 2023-24)

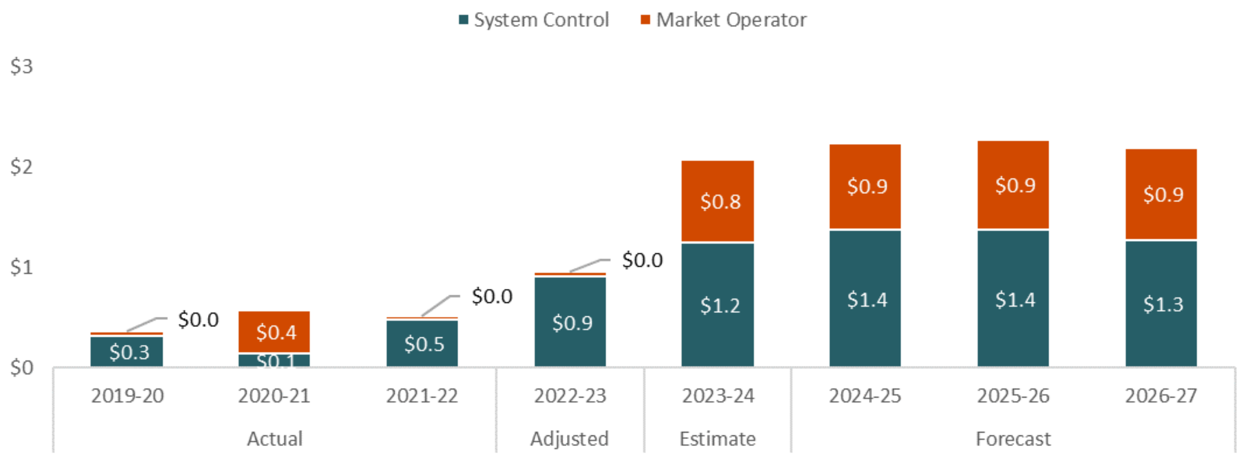
$ Real 2022-23	2024-25	2025-26	2026-27
Capex	8.2	8.0	7.4
Opex	2.2	2.2	2.1
Totex	**10.4**	**10.2**	**9.5**

5.6 Residual opex

Residual opex relates to legal, ICT services, and training. In some cases, these are the direct costs incurred by NTESMO or an allocation of costs within Core Operations. We consider these costs are likely to be recurrent in nature, and for that reason we have not adjusted the 2022-23 base year. We have then considered any specific cost drivers such as ICT costs related to new systems.

Figure 24 shows that that other costs will rise significantly in 2023-24. This relates to ICT costs to implement the new Settlements System and the transitional tools capex. It also includes a small amount of legal fees relating to Rule drafting and procedures.

Figure 24 - Residual opex ($m, real 2023-24)



Step changes

The primary cost increase relates to new ICT licensing and support costs for the Settlements System, Market Interactions Enablement and Transitional Tools, regulatory licence fees and legal fees related to NT Government policy advice, SCTC reviews and generator connection and operation disputes.

The ongoing Settlements System costs have been decreased by the unregulated revenue we expect to recover from TGen. TGen engage NTESMO to provide settlement functions in the Tennant Creek, Alice Springs, Kings Canyon and Yulara power systems. Further detail is provided in **Attachment 5.2**. **Table 13** provides a summary of the residual costs step change value.

Table 13 – Residual cost step change ($m, real 2023-24)

$ Real 2022-23	2024-25	2025-26	2026-27
Step Change	1.8	1.8	1.7

Total residual costs

Table 14 details the total residual cost forecast:

Table 14 – Total residual cost forecast in this Regulatory Proposal ($m, real 2024)

$ Real 2022-23	2024-25	2025-26	2026-27
Total Residual Costs	2.2	2.3	2.2

6. Capital expenditure

In the current 2019-24 regulatory period we invested in new assets including transitional tools to manage renewables and a new Settlements System. In the next regulatory period we will make further investments in evolving our transitional tools and investing in a new TDE. We are proposing forecast capex of $41.5 million, of which the majority relates to a new integrated dispatch and control system termed the TDE.

Capex relates to costs incurred on assets. Assets are defined as having a useful life of over one year. We have applied this definition when determining if expenditure should be capitalised rather than relying on statutory accounting treatments. Capex is recovered over the life of the asset including depreciation (return of the asset) and a return on the asset.

The purpose of this Chapter is to set out our forecast capex for the next regulatory period. We compare the forecast capex to actual and estimated capex for the 2019-24 current period. We note that Chapter 7 of our proposal identifies the capex incurred in the 2019-24 period for which we seek retrospective recovery.

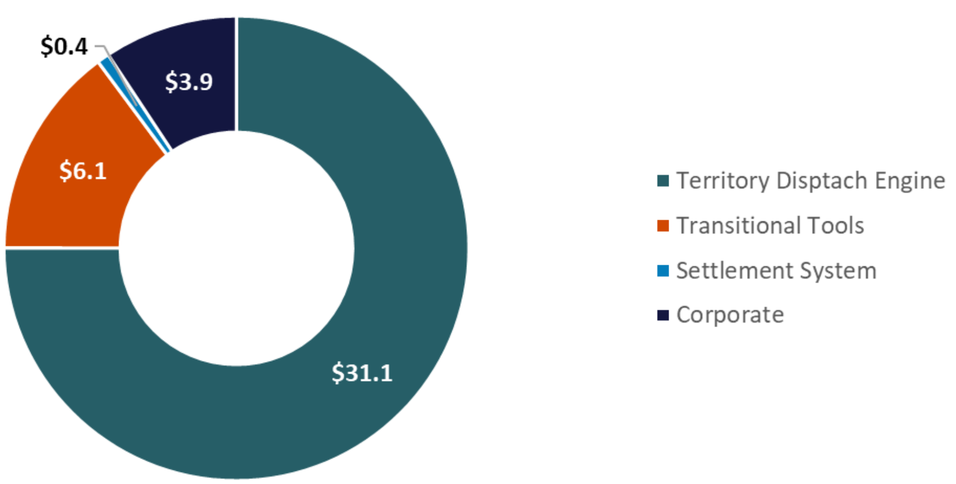
6.1 Overview of forecast capex

In aggregate we forecast that NTESMO's total capex is $41.5 million over the 2024-25 to 2026-27 regulatory period, or approximately $13.8 million each year on average.

Capex by driver

Figure 25 shows that the bulk of capex relates to our System Control functions, with the investment in TDE comprising 75% of forecast capex in the next regulatory period. The investment in evolving transitional tools to manage renewables until the TDE is implemented comprises 14.8%.

Figure 25 – Forecast capex by driver ($m, real 2023-24)



Capex trends

While opex is relatively recurrent, capex is generally 'lumpy', driven by specific investment drivers. This explains the year to year volatility in capex trends.

Figure 26 identifies actual, expected and forecast capex for System Control from 2019-20 to 2026-27 by capex drivers. This shows that investment in the current period was primarily on transitional tools. Capex rises significantly in the next regulatory period reflecting the implementation phase of the TDE. Corporate capex is a relatively low proportion of total capex.

Figure 26 – System control capex ($m, real 2023-24)

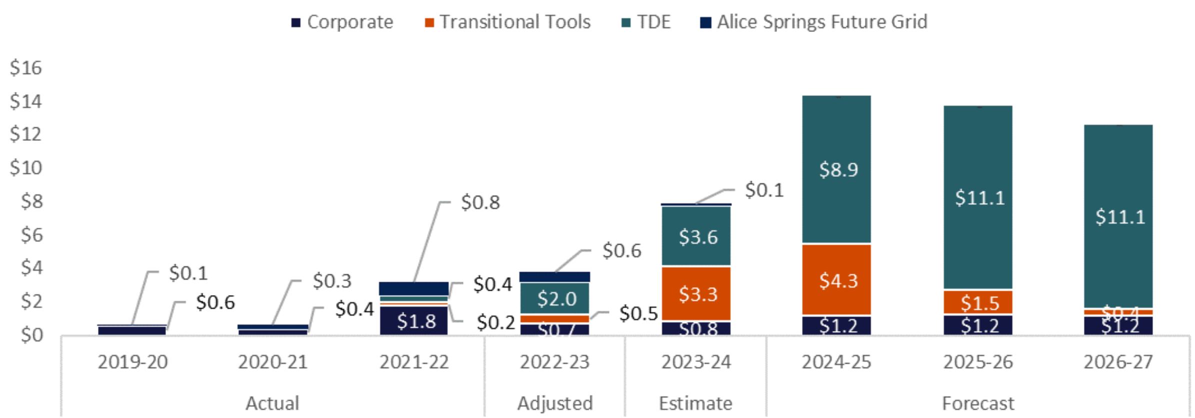
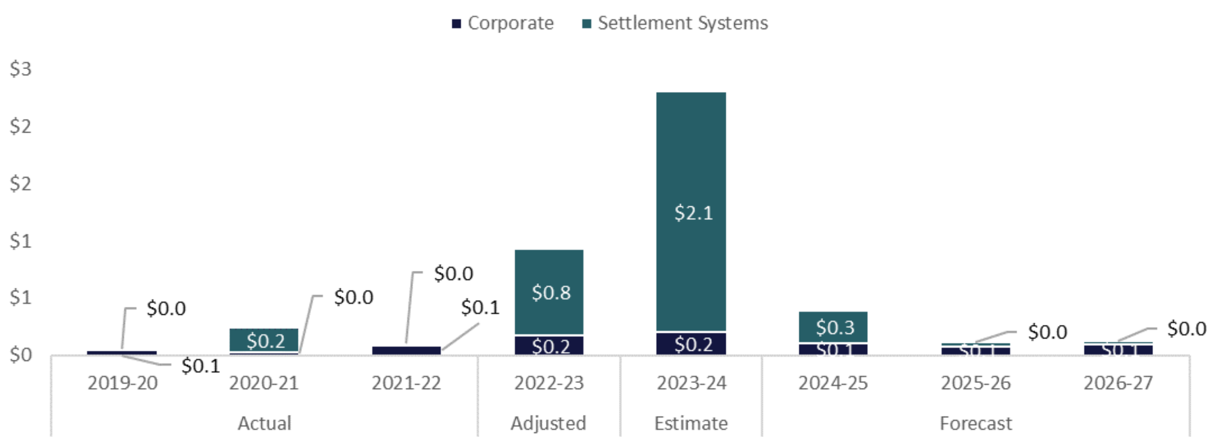


Figure 27 identifies actual, expected and forecast capex for the Market Operator between 2019-20 to 2026-27 by capex driver. It shows that the primary investment was in developing and implementing our Settlements System in the current regulatory period. The residual testing and updating capex will be relatively small.

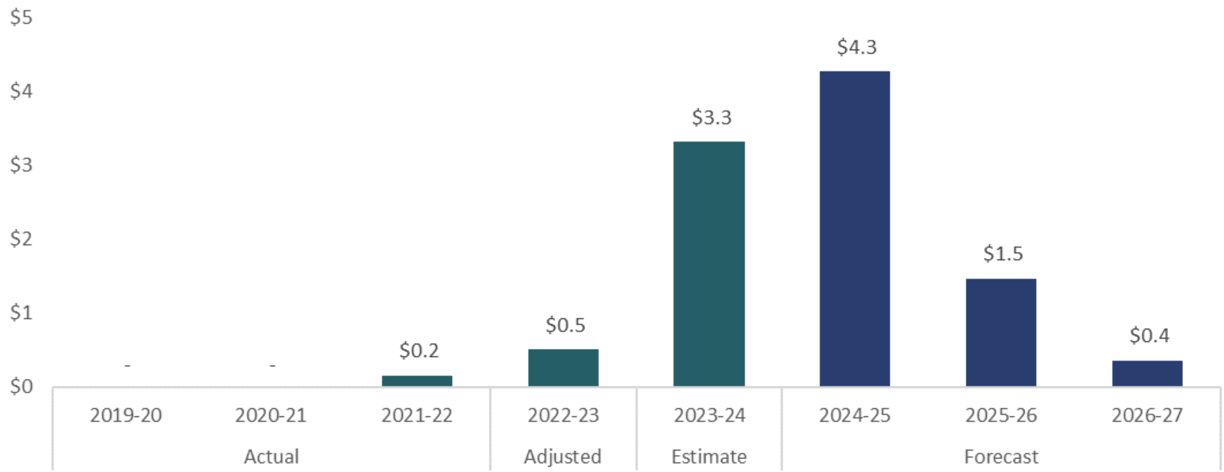
Figure 27 – Market Operator capex ($m, real 2023-24)



6.2 Transitional Tools

As noted in Chapter 3, we have incurred expenditure in the current regulatory period on developing transitional tools. These were focused on complying with our obligations under the SCTC to secure the power systems as renewables accelerated on the power system. In the next regulatory period, we will be evolving these tools as renewables further accelerate on the NT power systems including a step change in large scale renewable generation. **Figure 28** identifies the costs on transitional tools in the current and next regulatory period.

Figure 28 – Transitional tools ($m, real 2023-24)



Transitional Tools commissioned

During the current period, we incurred $4.0 million on implementing transitional tools designed to address compliance challenges with operating the power system with growing renewables. This includes:

- DKIS Demand Forecast (DKDF) – The intermittent nature of solar production means that the supply-demand balance is difficult to calculate unless there is accurate weather and forecast capacity inputs. The Demand Forecast tool has provided our controllers with more accurate information to forecast demand. In the absence of this tool, the DKIS may have been placed at more security risk. Further we would have needed to rely on much higher levels of spinning reserve, which increases the cost of supplying customers.
- The Forecast Compliance Tool (FCT) – Under the GPS, large scale solar farms must ensure dispatch is ‘firm’ at defined levels in their connection agreement. The FCT was required to monitor compliance with the agreement, and thereby meets one of NTESMO’s enforcement obligations. In the absence of a tool, System Control would have no systemised method to prove that a generator was not meeting a security standard, and therefore could not take action to reduce the solar generator’s level of dispatch.
- The Capacity Forecast Dispatch System (CFDS) – The CFDS is required to dispatch large scale generators against their capacity forecast in real time. The data is provided by generation connections through SCADA and processed by the CFDS for validity, MW capacity, MW constraint and ramp rate. The CFDS then calculates and issues dispatch instructions to the generator and monitors dispatch compliance and 30 minute ahead reserve requirements. In the absence of this tool, System Control would not have been able to securely dispatch large scale renewable generation.
- Frequency Control Ancillary Services Tool – As discussed above, a key challenge of transitioning to renewable energy is managing frequency and voltage on the power system. We have been relying on dispatching synchronous generation and spinning reserve as a fixed method of ensuring frequency control stays within secure bounds. However, with the retirement of synchronous generation and the emergence of new technologies such as the BESS, NTESMO recognises the need for a tool that can dynamically quantify the volume and dispatch of FCAS.

In addition, we have been involved in the Alice Springs Future Grid project. Further Information on historical expenditure on transitional tools can be found in Chapter 7.

Evolution of transitional tools

In the next regulatory period, we will be incurring $6.1 million on evolving the suite of transitional tools to cater for increasing behind the meter solar, and the expected connection of solar farms on the DKIS transmission lines. This includes:

- DKIS forecast tool (Stage 2) – The current tool will be expanded to include geographic information on cloud cover. This will be vital to understanding how demand varies at a local level. We consider this information is more critical as small scale solar expands and new large solar farms physically dispatch on the system in DKIS.
- System strength tool – The tool will be able to identify when system strength is likely to be compromised, ensuring that there is adequate security on the network.
- The Capacity Forecast Dispatch System (CFDS) – The current tool will be expanded to account for the increasing number of solar farms that are likely to have a connection agreement in place by 2024-25. The tool will include more sophisticated methodologies and incorporate more granular data.

Further information on the evolution of our transitional tools can be found in our RBC at **Attachment 6.1**. We note that the RBC does not constitute a business case as we are still in the planning stages of the project. The RBC provides a high level justification of need, options, scope and timing, and has been endorsed by our internal project governance committee to submit this RBC to the Commission in support of this Regulatory Proposal. We expect to provide a business case approved in accordance with the Commission as part of our revised proposal.

6.3 Territory Dispatch Engine

As discussed in Chapter 3 section 1, the pivotal investment for the next regulatory period is an integrated scheduling and dispatch tool termed TDE.

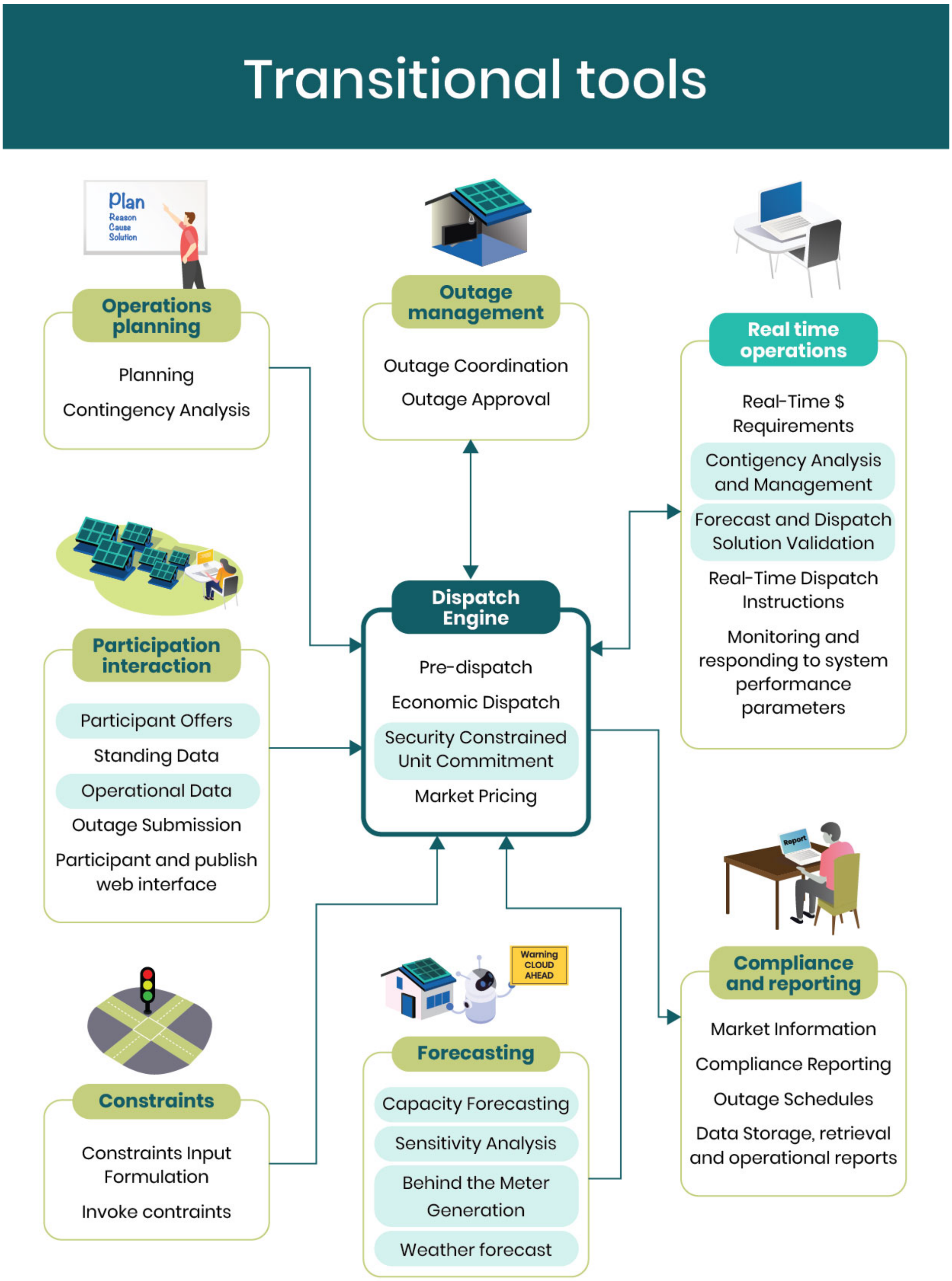
The TDE is necessary to manage the power system in real time as we face a step change in the growth of large-scale renewable connection and a decline in synchronous generation. We also will need to have a system that can integrate new technologies on our NT power systems such as synchronous condensers and battery energy storage systems. Small scale solar also presents considerable issues in managing the system on low load days.

The TDE will:

- Automate highly manual current processes, such as the processing of bids from market participants.
- Provide mechanisms that allow system control to manage renewable generation whilst still optimising economic dispatch.
- Provide tools that can implement system constraints without having to hold excess Essential System Services (ESS) while maintaining system security.
- Provide systems that will allow optimal entry of multiple market participants and new generators into the market.
- Review existing NTESMO work processes and implementing streamlined processes.

The transitional tools that we have developed and evolved will be embedded in the TDE. This can be seen in **Figure 29** which shows the transitional tools in teal shading. **Attachment 6.2** provides the RBC for the TDE project. As noted for the transitional tools project, the RBC is a high level justification of needs, options, scope and costings. We expect to provide further detailed information to the Commission as part of our revised proposal.

Figure 29 – Schematic of the TDE



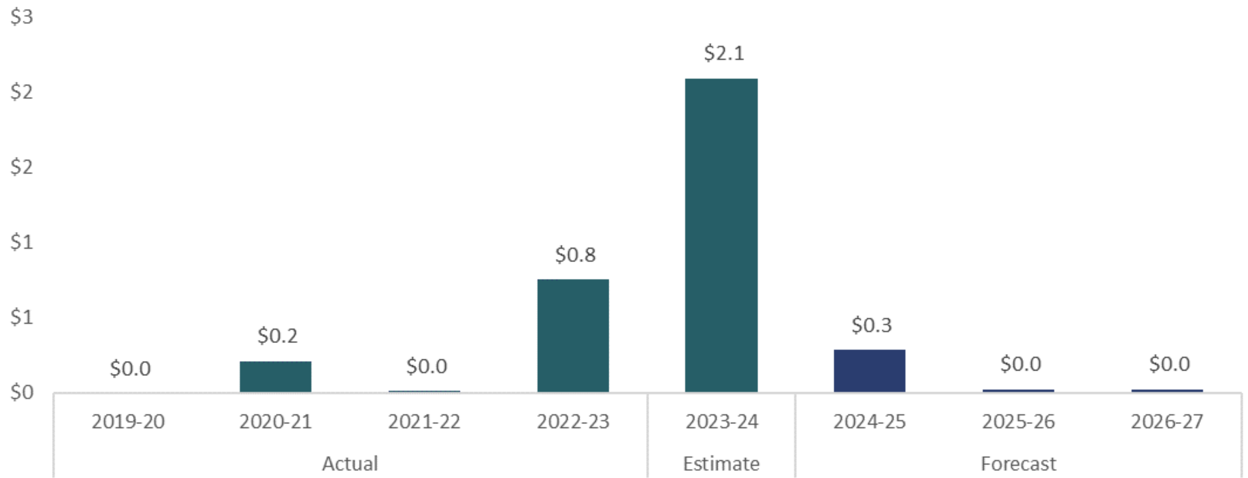
Note: The teal shaded shapes indicate a transitional tool has been applied.

6.4 Settlements System

In Chapter 3 section 2, we discussed the drivers of investing in a new Settlements System in the current regulatory period. The key driver was the volume of data required to settle the market had increased exponentially due to increased smart meter installation in the current period. We had been relying on a bespoke Excel version to adapt to increasing volumes, but the vendor advised that we had reached our data limits and that the version was at end of life.

Figure 30 shows the actual, estimated and forecast capex on the Settlements System from 2019-20 to 2026-27. It shows that we invested in developing the systems in the early years of the current regulatory period, and are implementing the solution in 2023-24, the last year of the current regulatory period. Capex in the next regulatory period relates to ongoing testing and updating of the system.

Figure 30 – Settlement systems capex ($m, real 2023-24)



6.5 Corporate overheads and capex

NTESMO incurs costs related to corporate overheads and corporate capex such as ICT. Below we describe our process for calculating the portion of corporate overheads that are capitalised, and the corporate capex that is allocated to NTESMO's functions.

Capitalisation of overheads

Capitalised corporate overheads are non-direct shared costs that are not wholly and exclusively associated with a single business unit but are necessary for the investment in capital projects. These costs are not immediately expensed as an overhead, but rather, included in the overall capex and amortised over the life of the assets.

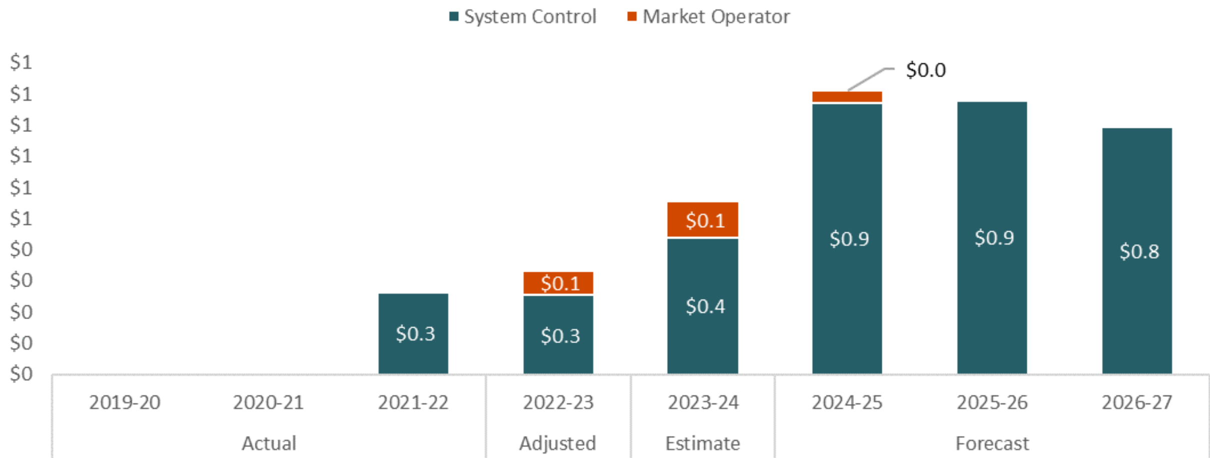
A portion of the total corporate overheads is capitalised, based on the overall percentage of corporate overheads that are considered to contribute to the capital program. This portion of costs are then apportioned to capex and opex based on NTESMO's ratio of direct capex and opex expenditure.

Our process is guided by the requirements of the Australian Accounting Standards and accepted by the AER. To fully comply with Australian Accounting standards requirements, Power and Water performed a comprehensive assessment of support costs to quantify the appropriate level of capitalised overheads.

NTESMO

Figure 31 shows that capitalised overheads in the last two years of the current regulatory period and forecast period consists of higher levels of capitalised overheads reflecting the significant capital investment undertaken by NTESMO. Further detail on capitalised overheads is provided in **Attachment 5.2.**

Figure 31 – Capitalised overheads ($m, real 2023-24)



Corporate capex

As a multi-utility, Power and Water incurs capex on corporate assets that are shared across business function.[14] This included ICT systems, corporate property, and fleet[15].

The Core Operations business unit (which includes NTESMO) is attributed a portion of the capex for these investments based on the methodology set out in the AER approved CAM (**Attachment 2.1**). We have then developed a Core Operations CAM (**Attachment 2.2**) to further allocate corporate costs to NTESMO's functions using the same principles of allocation[16].

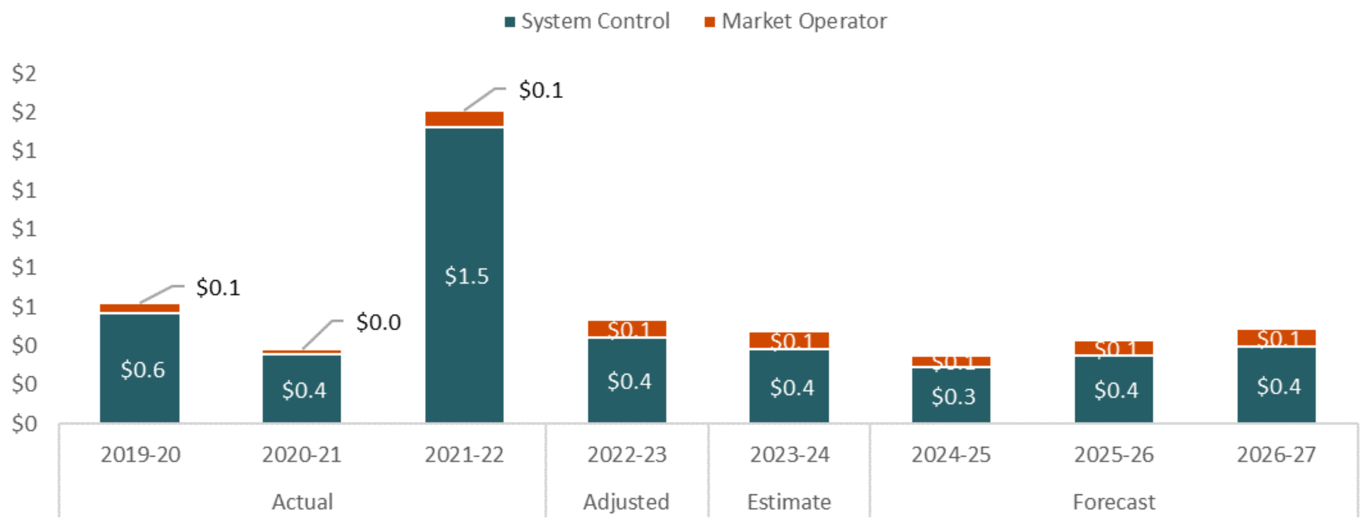
Figure 32 sets out the actual, estimate and forecast corporate capex, showing a significant increase from 2021-22 through to 2023-24. Corporate capex in the next regulatory period is lower than these levels.

14 In our 2019-24 proposal, we had not included the opening regulated asset base value of corporate assets allocated to System Control or Market Operator. We had also not included forecast capex for corporate assets.

15 For this Regulatory Proposal we are proposing to treat property and treat leases consistent with our AER proposal, where the costs are amortised and categorised as capex.

16 See discussion in Chapter 2 section 4 and Attachment 2.2

Figure 32 – Corporate capex ($m, real 2023-24)



The increase in NTESMO's share of corporate assets reflects significant investment in ICT corporate assets under Our New Operating Model initiative. The current Asset Management, Financial Management and Billing systems are at end of life, and do not enable us to perform efficiently. We also are investing to ensure our ICT systems are cyber-secure.

7. Proposed recovery of historical costs

During the current regulatory period NTESMO has responded to the challenges of a rapidly changing power system. The 2019-24 determination did not provide funding for this transition. Although unfunded, we developed new tools and processes to support the transition whilst maintaining system security and efficient dispatch. We are seeking to recover a portion of these unfunded costs relating to projects that will provide enduring value to our customers into the next regulatory period and beyond.

The purpose of this Chapter is to outline the unfunded activity that has occurred in the current regulatory period and discuss options for recovery in the next regulatory period.

We recognise that seeking recovery of historical costs can create price spikes for customers, particularly when recovery is sought over a short period. We have sought to balance the need to minimise price spikes with the commercial implications of inadequate compensation.

In our view, we responded prudently to the unanticipated and fast change in technology in an environment of regulatory uncertainty. Had we not responded to our circumstances, the NT power systems would have been subject to heightened security risks, more conservative and inefficient dispatch, and a slower path to renewable energy. The overarching design of the regulatory framework is to ensure that service providers are compensated for efficient decisions. This is to provide efficient incentives to invest and operate the business in a responsive, prudent and sustainable manner. Inadequate compensation undermines this objective.

Our proposed recovery of a subset of unfunded expenditure reflects a conservative approach. We have narrowed recovery to costs that are demonstrably prudent, efficient, clearly separate from the Commission's 2019-24 allowance, and provide an enduring benefit to customers.

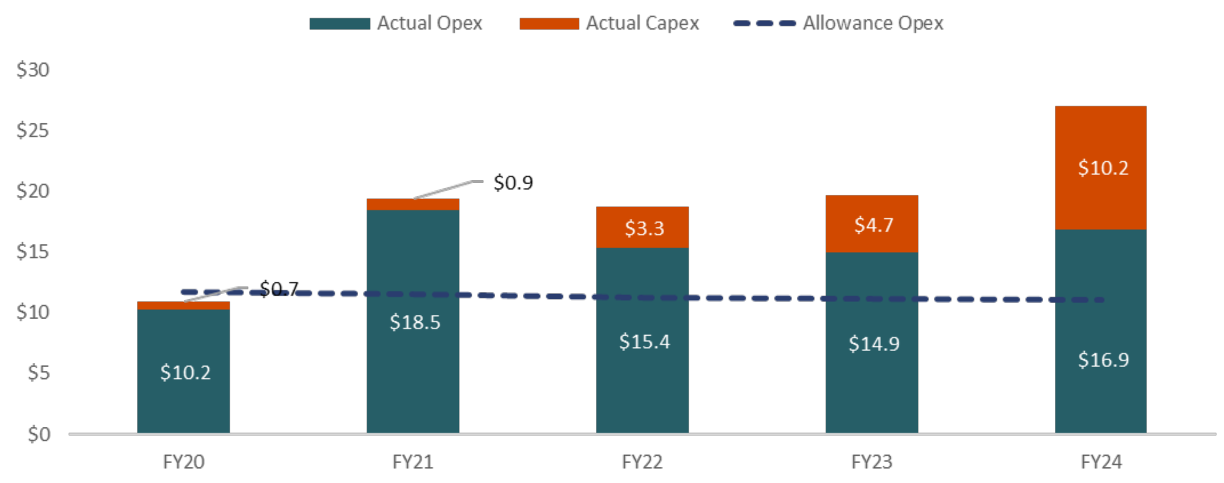
7.1 Current period expenditure

As outlined in Chapter 3, NTESMO's landscape has rapidly changed in the current regulatory period. To ensure the efficient and secure operation of the NT power systems and market, we made significant investments in new systems and processes, together with recruiting personnel during the current regulatory period. Although these activities were not funded in the last determination, they were critical to fulfil our legislated role. Had they been deferred, customers would have faced increased risks of system events and the NT would be on a slower pathway to renewable energy.

These activities were not included in the last determination as we had assumed, based on the reform timeframe proposed at the time, that the NTEM reforms would precede the significant power system evolution that has occurred. It was assumed that the NTEM reforms would incorporate the rule and technical changes required to facilitate the power system evolution. As such, we understood that a cost pass through event would be triggered in the current period. The approach to only seek costs associated with standard operation of NTESMO at that time, was based on discussions with the Commission which indicated costs of a 'speculative' nature should not be included in our proposal.

We expect that total expenditure will exceed the Commission's allowance by $38.9 million (real $2023-24) by the end of the current regulatory period as seen in **Figure 33**.

Figure 33 – Difference between actual costs and Commission's allowance for System Control and Market Operator combined ($m, real 2023-24)



As discussed in previous chapters, these activities have allowed us to:

- maintain system security as the power system evolves faster than anticipated
- ensure the control room has the appropriate tools to administer new Network Technical Code and SCTC requirements (including the GPS)
- continue to settle the virtual market within regulated timeframes with the increasing settlement complexity
- process a significant increase in generator connections
- provide design advice to the NT Government and undertake code review and amendments
- compressed incident reporting timeframes and improved action tracking
- fit out of a second control room responding to the Covid-19 risk
- improve our regulatory compliance
- ensure sufficient control room operators as a number of operators transition to retirement.

Undertaking these activities in the current regulatory period was critical to maintaining system security and efficiently operating the NT power systems and market. If we did not invest, the result would have been:

- increased risk of power disruptions, including major system events
- increased cost of generation through avoidable conservative dispatch decisions
- financial risk to system participants of delayed settlement activity that underpins their power purchase agreements
- increased risk of not meeting the NT Government 50% RET
- regulatory reform was likely to not be fit for purpose.

Customers and stakeholders have benefited from this expenditure and will continue to do so into the future.

7.2 Approach to determining recovery

As the System Controller, we believe that although unfunded, undertaking the above activities was in the best interest of our customers and system participants. With this in mind, we consider that recovery of these costs is reasonable.

It should be noted that the Commission's 2019 determination only allowed for opex recovery. It did not incorporate a risk margin nor a profit margin. As such, if unfunded, the broader Power and Water business will need to absorb the $38.9 million in additional expenditure.

During the current regulatory period, we sought advice from the Commission on whether a cost pass through could be triggered for these events, which was not supportive. We have subsequently investigated recovery options through this process.

In determining what portion of the $38.9 million should be recovered, we sought guidance from our stakeholders. Our second round of consultation, sought feedback on the principles we should apply to determine the costs that should be retrospectively recovered.

Stakeholders agreed with our principles but considered that further information and analysis should be considered. In formal submission, they also raised concerns with tomorrow's customers' paying for yesterday's customers expenses.

We have responded to stakeholder feedback and adjusted our principles accordingly. We have taken a conservative approach and sought only to recover those costs that are demonstrably prudent, efficient, clearly separate from the Commission's 2019-24 allowance, and provide an ongoing benefit to customers. Based on this assessment, we have only included a subset of costs for recovery.

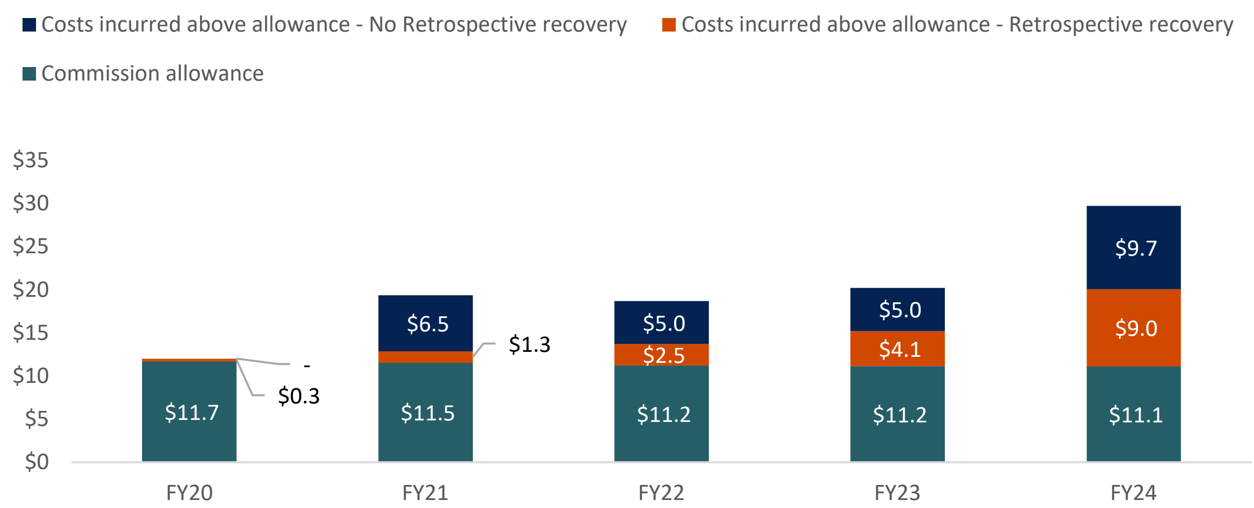
Stakeholders also raised concerns around price shock and indicated a preference to smooth recovery over time. In response, we have adopted a pragmatic approach to capitalisation and recovered retrospective costs over an extended period. Further detail on this approach is available in **Attachment 5.2**.

We have also proposed to defer recovery of 50% of the costs to the subsequent regulatory period. We propose that at the end of the next regulatory period, the unrecovered 50% be included in the RAB with an asset life of three years.

7.3 Proposed recovery

In total, we are seeking to recover expenditure of approximately $17.1 million of the $38.9 million spent as seen in **Figure 34** below.

Figure 34 – Split of retrospective cost recovery compared to non-recovery above allowance ($m, real 2023-24)



Power and Water is subsequently absorbing $2 million in expenditure. The activities that we seek to recover are outlined in **Table 15** for opex and **Table 15** for capex.

Opex recovery

Table 15 – Opex seeking retrospective recovery ($000, real 2023-24)

Opex	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Design and Rule Development	0.0	0.0	0.0	0.0	0.4	0.4
Settlements System Operational	0.2	0.9	1.0	0.2	0.8	3.1
Transitional Tools	0.0	0.0	0.0	0.0	0.3	0.3
Enhanced Capability	0.0	0.0	0.0	0.0	0.4	0.4
Total	**0.2**	**0.9**	**1.0**	**0.2**	**1.9**	**4.3**

The majority of the opex that we are seeking to recover relates to the provision of advice and assistance to policy development and code amendments. As outlined above, we did not include any expenditure for rule design and code amendments in the last determination as we expected it to be captured in the NTEM reforms and subsequent cost pass through.

While the NTEM reform trigger event did not occur in the current period, we nevertheless invested significant resources during the period in our capacity as 'code custodian', and as technical experts assisting the NT Government in the development of NTEM reform. This investment was realised by attending development and implementation working group meetings, undertaking investigations and drafting rule amendments. This effort has contributed significantly to the current draft policy directions and a number of drafted code amendments that are now awaiting finalisation of the policy directions. The costs have been captured in separate projects and we believe will provide benefit in any future reforms that are progressed.

The enhanced capabilities initiatives relate to forecast activities in 2023-24. The increasing market complexity has resulted in an expectation that NTESMO will provide advice on how we best meet these challenges. Although some of these items are linked to possible future reforms, it is important that NTESMO invest now to manage the change prior to reform and to ensure it has the required information to advise and respond to proposed reforms. Without this capability, NTESMO can only be reactive in nature and is unable to advocate in our customers interests.

The 2023-24 forecast includes the external expenditure for the following initiatives:

- managing renewables integration strategy
- market interactions enablement ongoing opex (use of MSATS)
- renewables hub planning
- web page content update.

The transitional tools initiatives, include Distributed Energy Resource (DER) licence costs, frequency control ancillary services training module and ongoing support for the tools developed.

The Settlements System estimate for 2023-24, relates to the first year of the ongoing opex. Additional information on these costs is available in **Attachment 7.2**.

Capex recovery

Table 16 identifies the capex for which we are seeking retrospective cost recovery.

Table 16 – Capex seeking retrospective recovery ($000, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Alice Springs Future Grid	0.1	0.3	0.8	0.6	0.1	1.8
Settlements System	0.0	0.2	0.0	0.8	1.9	2.9
Territory Dispatch Engine (TDE)	0.0	0.0	0.4	2.0	2.6	5.1
Transitional Tools	0.0	0.0	0.2	0.5	2.3	3.0
Total	**0.1**	**0.5**	**1.4**	**3.8**	**6.9**	**12.8**

The TDE and Transitional Tools capex initiatives relate to supporting the power system evolution that has occurred to ensure we have the appropriate tools to effectively fulfil our role as the System Controller. The transitional tools also includes projects that responded to rule changes that occurred to update GPS. The Settlements System initiative relates to the settlement function of the Market Operator.

Individual attachments providing further detail on the largest capex projects have been prepared for:

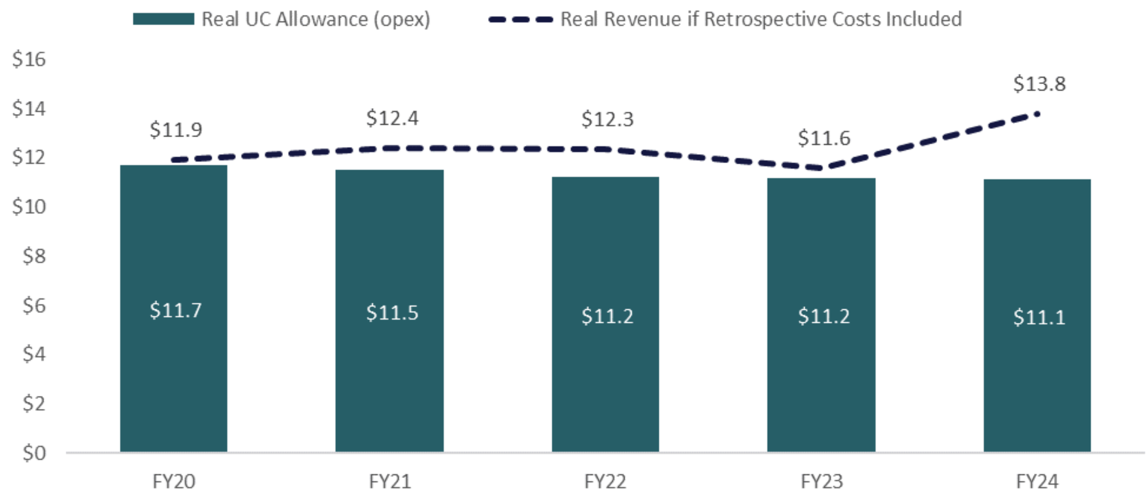
- Transitional Tools actual expenditure – **Attachment 7.1**
- Settlements System – **Attachment 7.2**
- Evolution of Transitional Tools Program – **Attachment 6.1**
- Territory Dispatch Engine – **Attachment 6.2**

Further detail on the approach to capitalisation is also available in **Attachment 5.2**.

The remaining capex project is Alice Spring Future Grid, which is a collaborative project focused on removing barriers to further renewable energy penetration in the Alice Springs power system. This represents NTESMO's portion of the project funding and relates to technical design trials for behind the meter PV solutions and their integration into the power system. The findings from these trials will be published in the Alice Springs Future Grid Roadmap to 2030 Report and will underpin our DER solutions moving forward. Undertaking these trials in a partnership arrangement was the least cost approach to identifying possible future solution to our DER challenges.

Given the capital nature of these projects, they have been included in the RAB from the time the expenditure was incurred. We have identified the return on and return of (depreciation) that we would have earned in the current period. This along with the opex recovery would result in the following revenue in comparison to the previous allowance as seen in **Figure 35**.

Figure 35 - System Control and Market Operator Revenue ($m, real 2023-24)



Unrecovered costs

Whilst we are not proposing to recover $21.8 million in historical unfunded expenditure, it is critical to note that this does not mean that these costs were inefficient or did not provided value to our customers. The activities these costs related to included:

- increased incident reporting capabilities which significantly reduced reporting timeframes
- fit out of a backup control room in response to Covid-19 challenges
- facilitating increased generator connections
- improving regulatory compliance monitoring and reporting
- increased support for demand forecasting
- ongoing maintenance and operation of the dynamic system model.

Although required at the time, these activities did not meet the recovery criteria developed in consultation with our stakeholders. In most instances, the costs were either not captured directly in projects or they did not meet the criteria of providing ongoing benefit to customers, that is, the benefits were realised within the period. These costs have been absorbed by Power and Water in this instance, however this is unsustainable and cannot occur into the next regulatory period. For this reason, our Regulatory Proposal has sought to mitigate the current level of uncertainty through a shortened regulatory period and cost pass through mechanisms, however a pragmatic approach to within period changes is required.

7.4 Approval under the regulatory framework

As outlined in Chapter 2, under the NT regulatory framework the Commission has significant discretion in making revenue determinations. As such, NTESMO has relied on the intent and the guiding objectives of both the ER Act and UC Act. Specifically under section 6(2) of the UC Act:

> *'In performing the Utilities Commission's functions, the Utilities Commission must have regard to the need:*
>
> *(a) to promote competitive and fair market conduct;*
> *(b) to prevent misuse of monopoly or market power;*

(c) to facilitate entry into relevant markets;
(d) to promote economic efficiency;
(e) to ensure consumers benefit from competition and efficiency;
(f) to protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries;
(g) to facilitate maintenance of the financial viability of regulated industries; and
(h) to ensure an appropriate rate of return on regulated infrastructure assets.'

There is significant discretion available to the Commission and also a precedent at the last determination where historical I-NTEM costs (pre-determination) were incorporated in the determination. As such, we do not consider there are any regulatory barriers preventing this consideration.

Given the unique situation, the criticality of the activities undertaken and the significant cost burden modernising the power system has placed on Power and Water, the Commission in performing its functions, should consider recovery options of historical costs.

8. Establishment of opening RAB

In the 2019-24 determination, our revenue allowance was based on operating expenditure only. This approach did not consider the value of past and future corporate assets allocated to NTESMO or contemplate that NTESMO would invest in new assets in the regulatory period. Our Regulatory Proposal estimates a RAB value as at the end of the current 2019-24 regulatory period.

The purpose of this Chapter is to identify the need to establish a RAB for the depreciated value of capex allocated to NTESMO before 2019, and to include the value of depreciated capex in the 2019-24 period.

8.1 Purpose of developing an opening RAB

The RAB is a financial construct to determine the efficient returns that a monopoly service provider should receive for past and future capex.

The 2019-24 regulatory proposal did not propose any forecast capex projects nor include the depreciated value of past investment. As such the Commission's determination did not include a RAB value.

In hindsight, our 2019-24 regulatory proposal should have included amounts relating to historical depreciated value of corporate assets allocated to NTESMO. Further, in the 2019-24 period we have both direct and corporate capex that was not included in at the time.

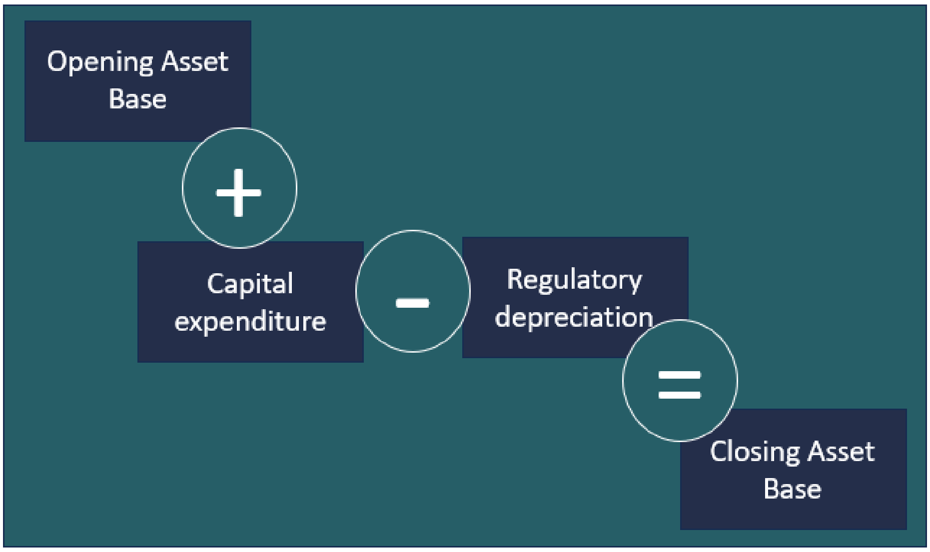
To ensure that NTESMO can recover its efficient costs for past capex in the next regulatory period, we are proposing the establishment of an opening RAB based on the RAB value as at 30 June 2024. This will allow us to recover a return on and return of (depreciation) for these assets in the next regulatory period. This is consistent with 'best practice' regulation including the prescribed methods used by the AER under the NT NER.

In Chapter 7, we discussed the elements of actual capex where we sought retrospective recovery of revenue for the 2019-24 period. This has also been based on the RAB value discussed below.

8.2 Roll forward methodology

Power and Water is seeking to apply a roll forward methodology consistent with the AER's approach. The roll forward method is depicted in **Figure 36**. This includes establishing a RAB value at the beginning of the 2019-24 period, and then including actual capex, and regulatory depreciation to roll forward that value in each year of the 2019-24 period. These elements are discussed below.

Figure 36 – Roll forward methodology



Initial value of RAB in 2019-24

In 2014, Power and Water undertook a corporate wide valuation of our RAB. This included allocating a portion of the existing regulatory value of corporate assets to the System Control function. In 2019, we updated the valuation to reflect depreciation and inflation. This was for the purpose of deriving a value for the RAB for distribution services provided by our regulated electricity network, and was subsequently accepted by the AER to establish an opening RAB. At this time, we also updated the RAB for all lines of business including NTESMO.

While this amount was not included in our 2019-24 regulatory proposal, our calculation of the RAB in the 2019-24 regulatory period has used this amount as the initial value as at 1 July 2019.

Actual capex

In Chapter 6, we identified actual direct and corporate capex incurred or estimated in the 2019-24 period as set out in **Table 17** below for System Control and Market Operator. The actual capex has been allocated to an asset class. We have used asset classes consistent with our approach for the AER distribution proposal.

Table 17 –Actual capex ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	0.6	0.6	3.3	3.9	8.0
Market Operator	0.1	0.2	0.1	1.0	2.3

Regulatory depreciation

The regulatory depreciation is deducted from the actual capex to derive a closing RAB for each regulatory year. We have identified the standard asset life and remaining asset life for each asset class and then applied straight line depreciation based on the standard asset life. **Table 18** identifies the depreciation profile.

Table 18 – Regulatory depreciation ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	(0.2)	(0.2)	(0.3)	(0.5)	(0.7)
Market Operator	(0.2)	(0.0)	(0.1)	(0.1)	(0.1)

8.3 Establishing a closing RAB in each year of the 2019-24 period

The closing value of the closing asset base for System Control and Market Operator for each regulatory year is set out in **Table 19**.

Table 19 – Closing RAB in 2019-24 period ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	1.9	2.3	5.3	8.7	16.0
Market Operator	0.4	0.6	0.6	1.5	3.7

As discussed in Chapter 9, the RAB value at the end of the 2023-24 period has been used to derive an opening value for the RAB in 2024-25.

9. Proposed revenue

Our proposed revenue is based on a building block approach with adjustments for retrospective revenue recovery from the current regulatory period. We have only sought to recover the revenue associated with a small portion of the increased historical costs. Our revenue calculation has also made adjustments for the 2024-25 first year of the regulatory period.

The Commission's determination will require a decision on the maximum revenue that we can recover for each year of the regulatory period through our regulated charges. We have proposed a building block approach that incorporates the following elements:

- The establishment of a RAB for NTESMO as set out in Chapter 8.
- Investment costs associated with our RAB, which is the value of our regulated assets at a point in time. The RAB comprises the depreciated value of our regulated assets, together with the forecast capex discussed in Chapter 6. Financing costs include a return on the RAB based on the current estimate of the rate of return, and depreciation of the RAB (often termed 'return of' investment).
- Forecast opex for each year of the regulatory period as set out in Chapter 5.
- An estimate of the taxation that would be paid. For this Regulatory Proposal, we have calculated a value of zero corporate tax liability. This is because our expected taxation costs including opex and depreciation have been calculated to be higher than our revenue for each regulatory year, implying that we would not incur a positive tax liability.

As set out below, we have adjusted the building block revenue to include retrospective recovery of a portion of our incurred costs in the 2019-24 regulatory period, and to adjust for the shortfall in revenue for the 2024-25 first year of the proposal.

9.1 Overview of proposed revenue requirements

Table 20 sets out the proposed revenue for the 2024-25 to 2026-27 regulatory period for System Control and Market Operator. This shows a significant increase in 2025-26 and a smaller increase in 2026-27. As noted in the next section, the 2024-25 amount relates to the expected recovery of revenues based on the approved 2024-25 pricing proposal. The difference between the building block revenue and expected revenue is reflected in the higher revenue forecast in 2025-26 and 2026-27. Further, we have proposed recovery of a subset of unfunded revenue from the 2019-24 period in the 2025-26 and 2026-27 proposed revenue.

Table 20 – Proposed revenue allowance for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	9.3	22.8	23.7
Market Operator	0.8	5.3	5.5
Total	10.1	28.1	29.2

Figure 37 provides further explanation of the drivers of higher revenue in the 2025-26 and 2026-27 revenue calculation for System Control and Market Operator in aggregate including:

- Building block calculations for 2025-26 and 2026-27 – These years reflect our building block calculations for operating expenditure allowance, return on and return of allowances, and taxation allowances. This is discussed in Chapter 7 section 2.
- True-up of actual and forecast revenue in 2024-25 – The first year of the next regulatory period was effectively set through the approved pricing proposal for 2024-25 as a transitional measure. We have included the forecast shortfall in revenue in 2024-25 in the last two years of the regulatory period based on our building block calculations. This is discussed in Chapter 7 section 3.
- Retrospective revenue recovery for 2019-24 regulatory period – We have also included additional revenue in the last two years of the period, relating to retrospective revenue recovery in the 2019-24 regulatory period. As noted in Chapters 5 and 6, NTESMO has incurred higher costs than allowed in the Commission's decision. Based on feedback from stakeholders, we have applied principles to identify the portion of the higher costs that we consider should be retrospectively recovered. This is only a subset (44%) of the total costs incurred. This is discussed in Chapter 7 section 4.
- Deferral of retrospective revenue – We have deferred 50% of the revenue associated with the retrospective revenue recovery for 2019-24 and the true-up of revenue for the first year of the next regulatory period. We have proposed to recover this amount in the three years following the completion of the next regulatory period. This is discussed in Chapter 7 section 5.

Figure 37 – Explaining drivers of higher revenue in 2025-26 and 2026-27 ($m, real 2023-24)

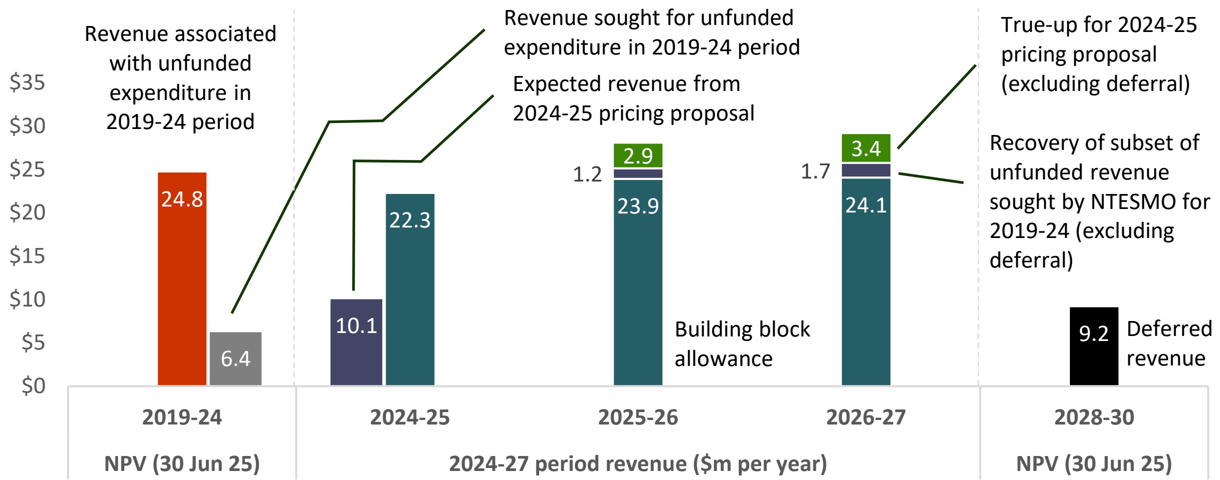


Figure 38 is presented in 2023-24 real dollars to ensure that reported amounts exclude the impact of inflation. In the following sections, we report revenue amounts in nominal dollars as per the process applied in AER determinations.

9.2 Building blocks for 2024-25 to 2026-27

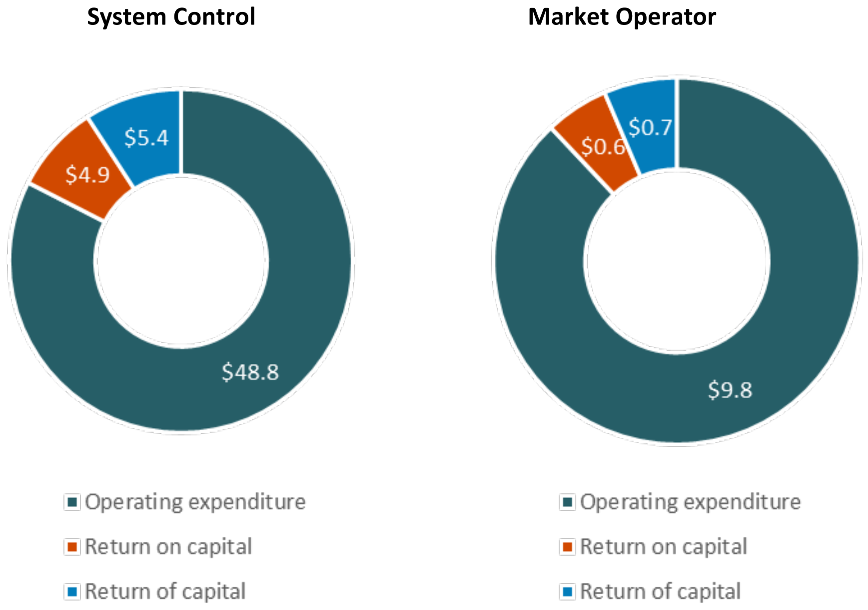
In this section, we discuss the calculations and inputs for each of the building blocks used to estimate forecast revenue for the next regulatory period. The total sum of the building blocks for each regulatory year for System Control and Market Operator is identified in **Table 21**.

Table 21 – Building block forecast for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	18.4	19.9	20.7
Market Operator	3.9	4.0	3.3
Total	**22.3**	**23.9**	**24.1**

Figure 39 shows that operating expenditure accounts for most of the revenue for both System Control and Market Operator forecast revenue. The return on and return of capital allowances are of similar magnitude.

Figure 39- Breakdown of System Control and Market Operator revenue for 2024-25 to 2026-27 ($m, real)



We note that building block revenues have been expressed in real 2023-24 dollars, consistent with our proposed opex and capex. This included the application of real cost escalation for labour in real 2023-24 dollars (that is, excluding forecasts of inflation).

Opex allowance

Opex is an annual cost that is unrelated to an asset that provides future services. The cost is passed through directly as a revenue item. Our forecast opex is set out in Chapter 5. **Table 22** identifies the forecast opex allowance in nominal dollars for System Control and Market Operator.

Table 22 – Operating expenditure allowances ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	16.6	16.5	15.7
Market Operator	3.5	3.5	2.8

Return on and return of capital allowances

A key input to determining the return on and return of capital allowances is the value of the RAB. The RAB is the sum of the depreciated value of past capex and forecast new capex. Chapter 8 discussed our approach and method for establishing an Opening Asset Base as at 1 July 2024.

The RAB has been rolled forward for each year of the next regulatory period using forecast capex and forecast depreciation. The nominal RAB for System Control and Market Operator is provided in **Table 23**. We note that we will use actual capex and depreciation to roll forward the asset base in the following regulatory period.

Table 23 – Value of Opening RAB ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	16.0	29.2	40.6
Market Operator	3.7	3.8	3.6

We have forecast a 'return on' investment allowance for each year of the regulatory period. The allowance is calculated by multiplying the nominal rate of return by the nominal value of the RAB. The rate of return represents the expected rate of financing required to finance a benchmark efficient business with similar operating characteristics. The nominal vanilla weighted average cost of capital (WACC) is the proportion of the return on equity and return on debt based on a defined gearing ratio. We have used a gearing ratio of 60%.

We have applied the methodology in the AER's Rate of Return Instrument to derive the nominal WACC for each year of the next regulatory period. This includes the methods for incorporating recent market data, and a trailing average portfolio method to calculate the return on debt. We consider that this approach is best practice for regulation in Australia. The values we have applied for both System Control and Market Operator are set out in **Table 24**. The values are expressed in nominal dollars.

Table 24 – WACC parameters

	2024-25	2025-26	2026-27
Return on equity	7.67%	7.67%	7.67%
Return on debt (trailing average portfolio)	4.24%	4.46%	4.68%
Nominal Vanilla WACC	5.61%	5.74%	5.88%

Based on applying the nominal vanilla WACC to the RAB, we have derived the return on allowance for System Control and Market Operator as set out in **Table 25**.

Table 25 – Return on allowances for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	0.9	1.7	2.4
Market Operator	0.2	0.2	0.2

To calculate the return of (depreciation) allowance, we have used a 'straight line' approach based on the value of the asset class in the RAB and the expected remaining life. We have utilised the AER's standard asset classes and lives to undertake this calculation. **Table 26** sets out the return on allowance for System Control and Market Operator based on the building block approach for each year of the 2024-25 to 2026-27 regulatory period.

Table 26 – Return of allowances ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	0.9	1.8	2.7
Market Operator	0.2	0.2	0.3

As discussed above, we sought to calculate a tax allowance based on the method in the AER regulatory framework. This has a value of zero. This is because our expected taxation costs including operating expenditure and depreciation have been calculated to be higher than our revenue for each regulatory year, implying that we would not incur a positive tax liability.

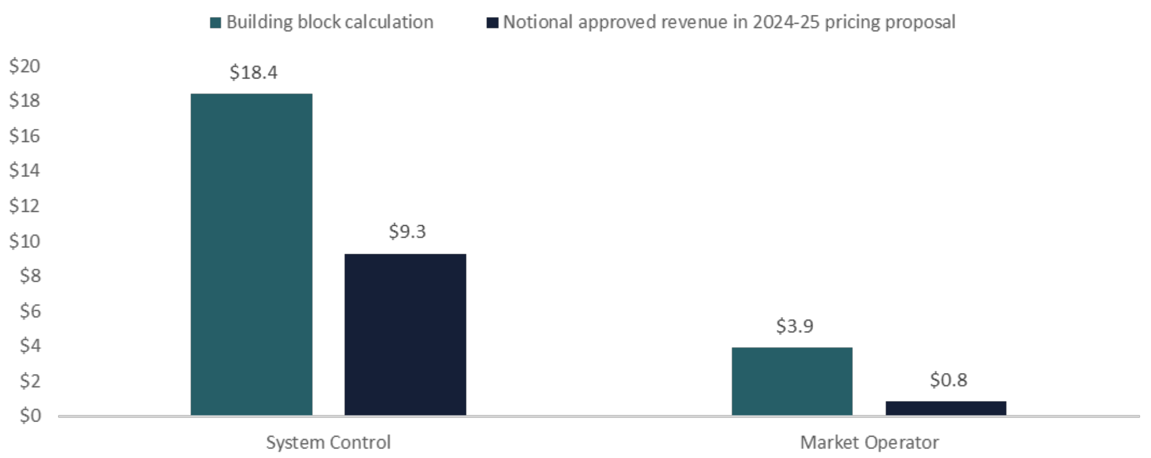
9.3 True-up of 2024-25 revenue shortfall

The building block revenue calculation does not consider the transitional arrangements for the 2024-25 first year of the regulatory period. The Commission agreed with our approach to set regulated charges in 2024-25 by rolling forward the approved 2023-24 regulated price with an adjustment for inflation. Effectively, this sets a notional approved revenue in the 2024-25 pricing proposal.

For System Control revenue, we estimate a shortfall of $9.1 million between our building block forecast and the notional approved revenue in the 2024-25 pricing proposal. For the Market Operator the shortfall is $3.0 million. **Figure 40** shows the relative difference.

We consider that the full amount of the revenue shortfall should be recovered as the Commission's decision to approve the 2024-25 prices was clearly a transitional measure until a full determination had been undertaken.

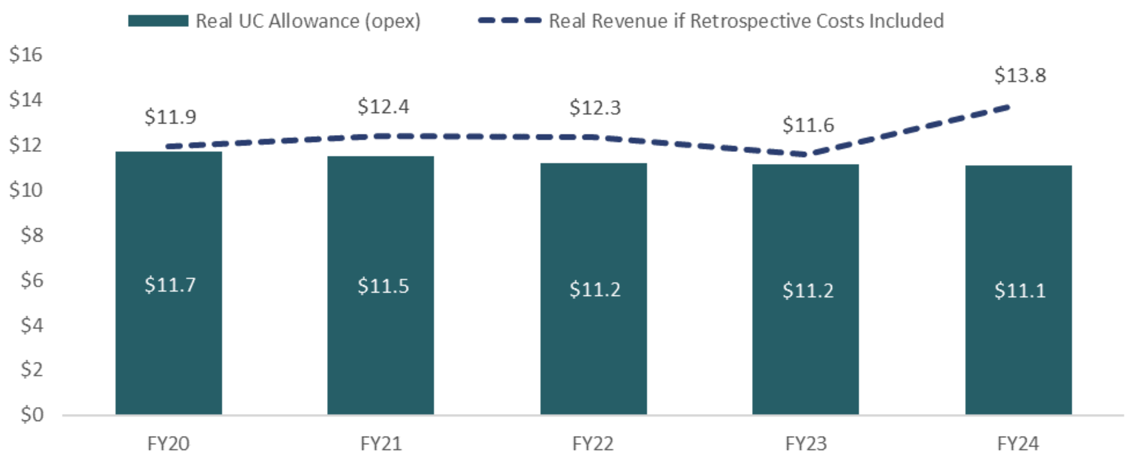
Figure 40 – Shortfall in revenue for the 2024-25 transitional year ($m, real 2023-24)



9.4 Adjustment for retrospective revenue recovery in 2019-24 period

We propose to recover a portion of the historical overspend, as outlined in Chapter 7. This equates to $6.4 million. **Figure 41** shows the recovery amounts sought compared to the Commission's allowance.

Figure 41 – Revenue recovery ($m, real 2023-24)



9.5 Deferral of revenue

We note that the combination of the true-up for 2024-25 prices together with the adjustment for retrospective revenue recovery has resulted in a combined impact of about $18.5 million. These revenue items would need to be recovered in the last two years of the period with an adjustment to account for the net present value of this amount.

In the second round of NTESMO's consultation, we sought feedback from stakeholders on whether they would be open to mechanisms to defer retrospective revenue to future periods, and if so, the level of deferral. As discussed in Chapter 4, there was a general view that deferral would minimise bill impacts and that somewhere between 50% and 75% were reasonable options.

In developing our revenue requirements we have proposed deferring 50% of retrospective costs to the following regulatory period. Given that the retrospective revenue recovery is much lower than the amounts identified in our initial consultation, we seek to recover the deferred amount in the first three years of the following regulatory period (that is from 2027-28 onwards). In total this has deferred about $9.2 million of revenue into the following period.

We consider that the mechanism to enable us to recover the deferred amount should be through the creation of a regulatory asset class with a life of three years.

10. Regulated charges and bill impacts

The regulated charges for System Control and Market Operator reflect the increased revenue requirement in 2025-26 and 2026-27. We are proposing the current charge design remain the same as this period.

The purpose of this Chapter is to identify the basis of regulated charges in the next regulatory period. We also identify the indicative regulated charge to apply to System Control and Market Operator services and the impact on customer's electricity bills.

10.1 Tariff design and billing arrangements

As noted in Chapter 2, we propose to continue the current arrangement of recovering our annual revenue for System Control and Market Operator charges from the retailer. This will be based on the volume of energy used by the retailer's customers on a cents per kilowatt hour (c/kwh) charge. We proposed charge structure changes to stakeholders, including a fixed charge component. Having received mixed feedback on the proposal, we have deferred this to the next regulatory period.

In the following regulatory period, we will consult with stakeholders on potential changes to our charge structures to ensure equity and efficiency. This includes a fixed charge to ensure that large customers and those without behind the meter PV generating systems solar are not being disadvantaged.

10.2 Indicative regulated charges

As noted in Chapter 2, the Commission has approved the escalation of charges for 2023-24 to account for inflation (based on the Australian Bureau of Statistics' June quarter 2023 consumer price index, weighted average of eight capital cities).

The regulated charges for System Control in 2025-26 and 2026-27 have been calculated by dividing the annual forecast revenue set out in Chapter 9 for System Control by the annual energy consumption forecast for Darwin-Katherine, Tennant Creek and Alice Springs regulated regions. The Market Operator charge has been calculated by dividing the annual forecast revenue identified in Chapter 9 for Market Operator by the annual energy consumption forecast for DKIS only.

We have presented indicative regulated charges in nominal terms. We have escalated the revenue presented in real terms in Chapter 9, by applying forecast inflation as presented in **Table 27**. The approach for estimating forecast inflation aligns with the AER's regulatory approach.

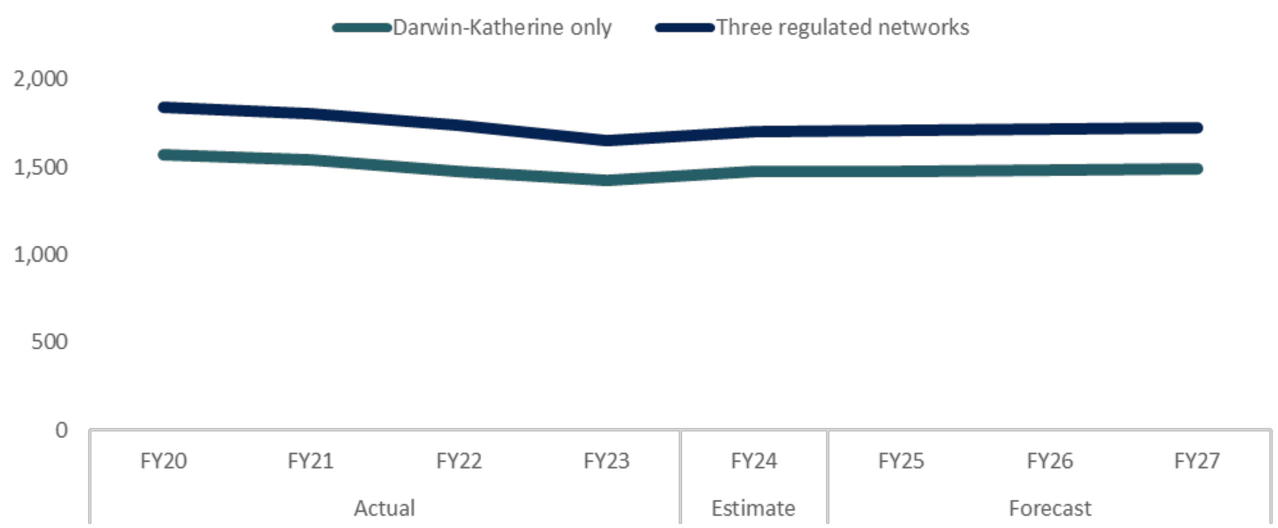
Table 27 – Forecast inflation

	2024-25	2025-26	2026-27
Forecast inflation	2.80%	2.80%	2.80%

Figure 42 shows that the energy consumption forecast for both DKIS and the combined three regulated networks will marginally increase in the next regulatory period. This has been based on an independent forecast of energy consumption from the grid that aligns with the estimates in our AER proposal.

Attachment 10.1 sets out the method and data underlying the forecast of energy consumption from the NT power systems.

Figure 42 – Annual energy consumption actuals and forecasts



The indicative regulated charges for System Control and Market Operator for each year of the next regulatory period are set out in **Table 28**.

Table 28 – Indicative regulated charges for System Control and Market Operator (c/kwh, nominal)

	2024-25	2025-26	2026-27
System Control	$0.005527	$0.013837	$0.014744
Market Operator	$0.000585	$0.003719	$0.003963

10.3 Bill impacts

Electricity retail prices charged to residential and commercial customers (those consuming less than 750 MWh of electricity per year) are set by the NT Government. The Electricity Pricing Order sets the maximum retail prices that customers may be charged for electricity and related services and has historically seen prices set below the actual cost of supplying electricity. The Pricing Order has not been historically indexed to changing costs in the electricity system. For this reason, our analysis has focused on what the retailer would charge the customer if NTESMO's regulated charge was fully passed through.

NTESMO comprises a very low proportion of NT customers' electricity bill. In the last year of approved prices (2024-25), System Control and Market Operator's combined impact was estimated to be less than 1.4% of the annual electricity bill of a typical small residential customer in the DKIS[17]. Despite the increase in proposed regulated charges in 2025-26, the combined impact is still very low and estimated at 4.9%. **Figure 43** shows the change in composition of System Control costs, assuming all other costs in the NT Power Systems stay constant in real terms.

[17] This calculation is based on the Pricing Order charges applied to a customer consuming 8,500kWh per annum and the estimated CSO per customer as per the Northern Territory Electricity Retail Review 2019-20

Figure 43 – NTESMO's contribution to typical DKIS residential electricity bill -comparison of 2024-25 to 2025-26

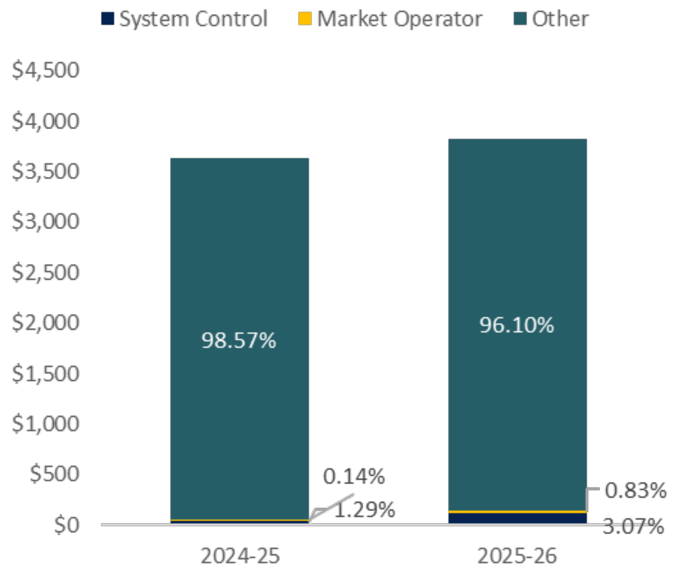


Table 29 shows the indicative change in electricity bill impacts between 2024-25 and 2025-26 for a retailer's customer in Alice Springs and Tennant Creek that have System Control regulated charges apply. The retailer's customers in these regulated regions do not receive a Market Operator charge. Customers under 750 MWh will continue to be protected by the NT Government's pricing order.

Table 29 – System Control regulated charge impacts for customers in Alice Springs and Tennant Creek ($, nominal)

	Volume (kwh)	2024-25 Charge	2025-26 Charge	Change ($)	% change
Small Residential	8,500	$47	$118	$71	150%
Large Residential	15,000	$83	$208	$125	150%
Small Medium Business	30,000	$166	$415	$249	150%
Medium Business	150,000	$829	$2,076	$1,247	150%
Large C&I	500,000	$2,764	$6,919	$4,155	150%
Industrial	1,000,000	$5,527	$13,837	$8,310	150%
Large Industrial	6,000,000	$33,162	$83,024	$49,862	150%

Table 30 shows the change in bill impacts for a retailer's customers in DKIS that have both System Control and Market Operator regulated charges apply. Customers under 750 MWh will continue to be protected by the NT Government's pricing order.

Table 30 – System Control and Market Operator regulated charge impacts for customers in Darwin-Katherine ($, nominal)

	Volume (kwh)	2024-25 Charge	2025-26 Charge	Change ($)	% change
Small Residential	8,500	$52	$149	$97	187%
Large Residential	15,000	$92	$263	$172	187%
Small Medium Business	30,000	$183	$527	$343	187%
Medium Business	150,000	$917	$2,634	$1,717	187%
Large C&I	500,000	$3,056	$8,778	$5,722	187%
Industrial	1,000,000	$6,112	$17,557	$11,445	187%
Large Industrial	6,000,000	$36,672	$105,341	$68,669	187%

11. Within Period Processes

Within the period, we have proposed a pass through mechanism to enable recovery of costs for regulatory reform, major system events and a change in the location of personnel.

The purpose of this chapter is to identify the basis of the pass through events that may trigger an increase in our costs. Finally, we discuss the mechanism for managing uncertainty in the period through nominated pass through events.

11.1 Annual reporting framework

As we mature our economic regulatory processes it has become apparent that an annual regulatory reporting framework would assist both the Commission and NTESMO with monitoring NTESMO's annual operating and capex by function. We note that Power and Water's regulated network business provides annual audited data to the AER on their expenditure. This has helped provide the AER with an understanding of variances and drivers of expenditure. We consider this process would also be beneficial in assessing our regulatory determinations in future periods, for instance, by demonstrating that corporate costs have been allocated in accordance with approved cost allocation methods.

We propose that the reporting process would be simplified in comparison to the annual process for the regulated network business. We propose that in November of each year, we provide data relating to the audited accounts of the previous financial year including:

- audited data on our capex
- audited data on our opex including by cost categories such as personnel, professional fees and other costs, and corporate overheads by the relative function performed by System Control and Market Operator.
- information on amounts relating to an approved cost pass through event (please see section below)
- audited data on revenues received from retailers.

11.2 Pass throughs

The forecasts contained in our proposal are based on Power and Water's current corporate structure and NTESMO's structure within Power and Water and the current legislative and regulatory instruments applicable to NTESMO's functions, obligations and activities. Our forecasts have not included the potential costs impact of anticipated market reforms and consequential regulatory changes impacting NTESMO's obligations, functions and activities because there is considerable uncertainty on the scope and timing of these regulatory changes.

To address this uncertainty we have proposed a cost pass through mechanism which will provide us with an ability to recover sufficient revenue should certain nominated events occur which increase our costs of meeting our obligations, functions and activities. The accepted rationale for pass through events is that changes in costs of providing regulated services, due to events over which the NTESMO has no control, undermines the revenue forecast underpinning the revenue requirements. This in turn would lead to the NTESMO having insufficient revenue to meet its obligations and functions. The pass through events mechanism fills any gap left after all other avenues to address the risk such as event avoidance, mitigation, commercial insurance and self assurance have been exhausted.

Our proposed pass through mechanism is set out in **Attachment 11.1** and has the following key elements.

Nominated pass through events

We are proposing that the Commission's determination provide for four pass through events, based on regulatory or market reforms, major system response events and terrorism or cyber attacks.

Proposed cost pass through process

If any of the nominated pass through events occur we propose a process for the notification and substantiation of the event by NTESMO to the Commission and the capturing of the increased costs which would be audited, assessed by the Commission and if accepted as efficient and prudent recovered on a lagging basis through the next annual pricing proposal.

The proposal is that a materiality threshold will not apply such that an application for the pass through of costs could be made in response to any increase in costs. This is because the impact of these event are likely to be incremental and cumulative in nature and NTESMO will have very limited capacity to reprioritise its expenditure within its allowed revenue to meet these increased costs. The increase in costs will be captured in NTESMO's financial system and the cost pass through application will be supported by evidence that the increased costs are incremental costs that have been incurred solely as a consequence of the change event and were therefore outside the normal variation from forecast that would normally be expected to occur during a regulatory period.

11.3 Annual Price Adjustments

Consistent with current processes, we propose that NTESMO submit an annual pricing proposal to the Commission at least three months before the commencement of the 2025-26 and 2026-27 regulatory year.

Attachment 11.2 sets out our proposed mechanism for setting annual prices for the last two years of the regulatory period. The process largely aligns to the current approach set out in our AER proposal, which relies on the revenue allowance set by the Commission, but which includes provisions for adjustments to

- Recognise under and over recovery amounts in previous years in accordance with a set formula.
- Account for changes in forecast energy consumption.
- Account for changes in the cost of debt calculation of the rate of return.
- Enable pass through amounts to be provided in the year following an approved pass through event.

Attachment List

Attachment No	Attachment Title
2.1	Australian Energy Regulator Approved Cost Allocation Methodology
2.2	Core Operations Cost Allocation Methodology
2.3	Project Investment Delivery Management Standard
4.1	Stakeholder Engagement Report
5.1	Activity Allocation and Obligation Mapping
5.2	Operational Expenditure Forecast
6.1	Evolution of Transitional Tools Program Regulatory Business Case
6.2	Territory Dispatch Engine Regulatory Business Case
7.1	Transitional Tools Compliance Summary
7.2	Settlements System Compliance Summary
10.1	Energy Consumption Forecast
11.1	Pass Through Mechanism
11.2	Annual Pricing Escalation Mechanism
12	Models

Abbreviations

Abbreviation	Description
AER	Australian Energy Regulator
CFDS	Capacity Forecast Dispatch System
capex	Capital Expenditure
Commission	Utilities Commission of the Northern Territory
CPI	Consumer Price Index
DER	Distributed Energy Resources
DITT	Department of Industry, Tourism and Trade
DKIS	Darwin-Katherine Interconnected Power System
DKDF	DKIS Demand Forecast
EPMC	Enterprise Portfolio Management Committee
ER Act	*Electricity Reform Act 2000*
FCAS	Frequency Control Ancillary Services
FCT	The Forecast Compliance Tool (FCT)
GOC	Government Owned Corporation
GPS	Generator Performance Standard
ICT	Information Communication and Technology
INTEM	Interim NT Energy Market
kW	Kilowatt
kWh	Kilowatt hour
kVA	Kilovolt ampere
LV	Low Voltage
MSATS	Market Settlement and Transfer Solution
MW	Megawatts
MWh	Megawatt hours

Abbreviation	Description
NEM	National Electricity Market
NER	National Electricity Rules (or Rules)
NMI	National Metering Identifier
NT	Northern Territory
NTEM	Northern Territory Electricity Market
NTESMO	Northern Territory Electricity System and Market Operator
opex	Operating Expenditure
Power and Water	Power and Water Corporation
PIDF	Portfolio Investment Decision Framework established by the Project Investment Delivery Management Standard
PV	Photovoltaic (Solar PV)
RBC	Regulated Business Case
RET	The NT Government's Renewable Energy Target
RAB	Regulated Asset Base
SCADA	Supervisory Control and Data Acquisition
SCTC	System Control Technical Code
TDE	Territory Dispatch Engine
TGen	Territory Generation
UC Act	*Utilities Commission Act 2000*
WACC	Weighted Average Cost of Capital

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