NTESMO

Revised Regulatory Proposal

2024-25 to 2026-27

April 2025

Version history

Version number	Date of submission
Version 1	28 February 2025
Version 2	24 April 2025

About this report

Power and Water Corporation submits this Revised 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 and the documents in the Attachment list is the Revised Regulatory Proposal and supersedes the regulatory proposal submitted on 23 December 2024. This Revised Regulatory Proposal seeks to comply with the Commission's decision paper published in September 2024 which establishes the regulatory framework (the Commission's approach).

This document sets out the Northern Territory Electricity System and Market Operator's (NTESMO's) proposed costs and regulated charges for the 1 July 2024 to 30 June 2027 regulatory period (2024-25 to 2026-27 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 how we have complied with the Commission's approach which applies to the 2024-25 to 2026-27 regulatory period.
- Chapter 3 provides information on how NTESMO has and is responding to a rapidly changing landscape including increasing renewables technologies connecting to the power system, the complexity in settling market data and adapting to the anticipated Territory Energy Market reform.
- Chapter 4 identifies the extent to which stakeholders have been consulted.

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

- Chapter 5 provides information on forecast operating expenditure, including our methods, historical trends, drivers and costs.
- Chapter 6 provides information on forecast capital expenditure, including major projects, corporate capex and capitalised overheads.
- Chapter 7 provides information on the recovery amount relating to historical capital expenditure incurred above the 2019-24 allowance that we are seeking to roll into the opening RAB at depreciated cost in 2024-25 consistent with the Commission's approach.
- Chapter 8 describes the method and inputs to calculate an opening asset base 1 July 2024.
- Chapter 9 sets out the key components of the calculation of revenue under the building block approach and the 'true-up' for actual revenue in the 2024-25 regulatory year, consistent with the Commission's approach.
- Chapter 10 sets out our proposed design of charges and indicative charges.
- Chapter 11 sets out how we have complied with the pass through events and mechanism in the Commission's approach.

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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 Revised Regulatory Proposal.

Our Revised Regulatory Proposal comes at a time of significant and ongoing change in the Northern Territory (NT) power systems.

The pace of transition to renewable energy has been fast paced over the last five years and will continue to accelerate as we head to 2030.

In our next regulatory period, we expect that the NT Darwin- Katherine power system will see almost a quarter of existing thermal generating systems displaced with new large-scale solar farms. We also expect continued uptake of small-scale inverter-based technologies from our residential and commercial customers, with more than 1 in 4 customers having photovoltaic generating systems installed by 2030.

NTESMO's primary responsibility is to ensure a secure and reliable operation of the regulated power systems. We are navigating extraordinary challenges to maintain power system security to ensure the NT customers are provided with power, while we continue to enable new renewable generating systems and supporting technologies into the market. This has required a fundamental re-orientation in NTESMO'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 new renewable technologies in the NT power systems.

Similarly, our market operator has kept pace with pivotal changes in the NT electricity market to facilitate increased competition and better use of customer smart meter data. Our investment in a new Settlements System ensures timely and accurate bill settlements, reducing financial uncertainty for participants in the increasingly complex and evolving 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 a customer’s electricity bill, however it plays a critical role in managing the NT regulated power systems to provide electricity to customers. 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 nature of changes in the NT power systems are presenting great challenges for our business as we perform our legislative functions. NTESMO is vital for shepherding the NT’s transition to renewables and supporting technologies, both large-scale and -small-scale. 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 generating systems that are expected to retire over the next decade and beyond provide many security benefits to power systems, including 24-7 availability, frequency and voltage control services, system strength and inertia services.

System Control must ensure that we can meet these power system challenges to ensure customer’s electricity needs are met. Already in this period we have significantly revamped our operations, recruited more staff and invested in tools that help manage the growing connection of new renewable and supporting technologies to power our communities.

Our proposal represents proportionate and prudent investments undertaken to meet the challenges. In this regulatory period and the next, we expect a significant proportion of our existing synchronous generating systems to retire by 2027 and their generation to be replaced by large-scale solar farms and technologies required to support them. The complexity of decision making will grow exponentially as we ensure adequate generation is available and rely on new technologies to meet the shortfall in essential services needed to maintain power system security and reliability.

Our Revised Regulatory Proposal includes scaled investment in a new Territory Dispatch Engine that is critical to ensuring that System Control continues to meet its existing 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. This is an investment that will significantly reduce the risks of major system events and will improve the efficiency of dispatch decisions to the ultimate benefit of customers.

The Market Operator function in NTESMO has also had to evolve to meet the needs of a changing market in the Darwin-Katherine power system (DKPS). 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 DKPS, enabling market participants to settle their bills more efficiently.

Since our initial regulatory proposal was submitted in December 2023, the Commission has established a regulatory framework for the making of regulatory determinations including for this regulatory period. We welcome clarity in the regulatory framework and have sought to comply with the Commission’s directions.

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 transformational change including a marked acceleration in the uptake of renewable technologies. Our Revised Regulatory Proposal complies with the Commission's approach on a regulatory framework.

This is our Revised Regulatory Proposal for the 2024-25 to 2026-27 (2024-27) regulatory period, following our Initial Regulatory Proposal submitted in December 2023. In September 2024, the Commission published its decision paper on the regulatory framework to be applied to the 2024-27 regulatory period and future periods. This decision paper set out the regulatory approach, model and timing. The Commission's decision paper also provided guidance and sought further information on our Initial Regulatory Proposal. In December 2024, we submitted our Regulatory Proposal which the Commission requested we resubmit by 28 February 2025. This Revised Regulatory Proposal complies with the Commission's regulatory framework and addresses the Commission's requirements for further information.

NTESMO's role in the power system

NTESMO is a ring-fenced function of Power and Water Corporation (Power and Water). Our Revised Regulatory Proposal reflects this, and we are currently operating under the existing market rules instead of the Territory Electricity Market (TEM) reforms being developed by the NT Government.

The System Controller provides the critical role of overseeing the safe, secure and reliable operation of the Darwin- Katherine Power System (DKPS), 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 DKPS.

We recover regulated charges from 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's Electricity Pricing Order. While a small fraction of the bill, NTESMO is critical to maintaining power system security and economic efficiency of the NT's power systems for the benefit of NT customers. Further information is provided in Chapter 1 of this Revised Regulatory Proposal.

Regulatory framework

At the time of submitting our Initial Regulatory Proposal, a prescriptive regulatory framework was not established. The Commission's decision paper on the regulatory framework establishes a regulatory framework to apply for current and future regulatory periods.

Our Revised Regulatory Proposal complies with the Commission's decision for a three-year regulatory period from 1 July 2024 to 30 June 2027. We have also complied with the Commission's approach to apply a revenue cap to each regulatory year. Our Revised Regulatory Proposal applies a building block method to calculate revenue each year, with the ability to seek a pass through of costs for specified events following the Commission's determination. Further information is provided in Chapter 2 of this Revised Regulatory Proposal.

Responding to a changing power system

Our Revised 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 technologies and changes in the volume of meter data required to settle the market.

Our investment decisions align with our legislated functions and are proportionate responses to the changing landscape. If we do not act and build the necessary IT infrastructure and services, the NT power systems will be subject to heightened system security risk and reliability to the detriment of NT customers.

For clarity, our proposed forecast expenditure is to meet current and future drivers impacting our ability to meet our existing obligations. We will apply to the Commission for a pass through claim if our costs materially increase because of new obligations arising from the planned TEM reforms and where a need for Code and procedural changes are required to integrate supporting technologies, e.g. Battery Energy Storage Systems (BESS).

Shepherding the NT's transition to renewables

The shift from synchronous thermal generating systems to asynchronous renewable generating systems creates fundamental challenges for the scheduling and dispatch functions of the System Controller. This includes ensuring adequate capacity is available when photovoltaic (PV) generating systems are not producing energy. We also need to manage volatility of demand to cover momentary dips in generation from PV generating systems related to cloud cover. Finally, we must manage shortfalls in essential system services (ESS) that have historically been provided by synchronous generating systems.

We have and will continue to modernise our processes, tools and systems to progressively meet the challenges. This includes developing transitional tools and investing in a Territory Dispatch Engine (TDE) to meet the immediate challenges by automating and integrating our control and dispatch functions.

The TDE is the predominant driver of capital expenditure (capex) in this regulatory period, comprising $35.5 million (real 2023-24), approximately 88.3%, of forecast capex. The underlying need for the project is that a significant amount of synchronous generating systems is expected to retire and be replaced by large scale PV generating systems. Based on existing decommissioning plans it is expected that availability of thermal generation in the DKPS will reduce from 457 MW to 307 MW between 2026 and 2030.

The TDE is the means to uplift and integrate NTESMO's existing and impending transitional tools and business processes to ensure System Control can achieve efficient and stable real time dispatch to meet the expectations and demand requirements of electricity consumers. The NTESMO Dispatch Systems Roadmap Regulatory Business Case provides evidence that investment in the TDE will reduce the risk of major power interruptions, improve the efficiency of dispatch decisions, and enable the secure entry of new renewable technologies.

Prior to the implementation of TDE, we will continue to evolve our existing suite of transitional tools to meet new emerging challenges. The tools will improve the granularity of our demand forecasts including more geographic information on cloud cover, identify shortfalls in ESS, and improve how we monitor and dispatch large-scale generating systems and their supporting technologies. The transitional tools serve as a fundamental building block for the TDE and allow for a scaled introduction.

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

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 meter 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 could not keep pace with the increasing data requirements. Its implementation significantly reduces financial risk to system participants from delayed settlement activity, particularly since a 100% roll-out of smart meters is expected in the NT by 2029. The Settlements System is designed to be highly configurable to accommodate a wide array of potential functional amendments that will support a range of types of reforms that may arise in the future.

Rule development, technical and policy advice

NTESMO is required to review of the System Control Technical Code (SCTC) at a minimum every five years and propose changes. Additionally, NTEMSO provides technical and policy advice to the Commission and more broadly to government. This continues to be an important activity as challenges arise integrating and managing renewable technologies. We have forecast $0.4 million opex to support our five yearly review of SCTC.

Forecast revenue

Consistent with the Commission's decisions regarding the regulatory framework, we have applied 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 is expressed in 2023-24 real dollars. A breakdown of the forecast opex is at **Figure 1** and forecast capex is at **Figure 2**.

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

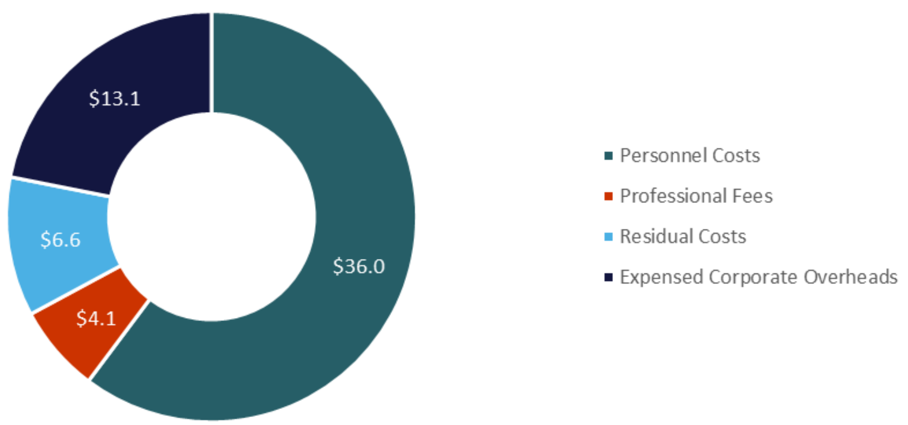
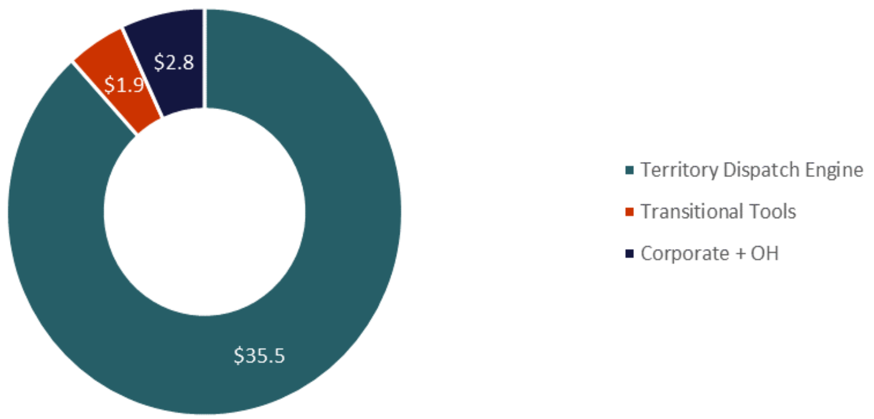


Figure 2 - Forecast capex by cost category ($m, real 2023-24)



The RAB comprises the depreciated value of historical and forecast capex. We have calculated a return on capital consistent with the approach used for Power and Water's regulated electricity 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 real terms, noting that this excludes the shortfall in actual revenue in 2024-25.

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

	2024-25	2025-26	2026-27
Capex*	$3.9	$22.4	$14.2
RAB (opening value)	$6.8	$10.1	$31.6
WACC (nominal vanilla)	5.68%	5.78%	5.89%
Return on capital	$0.4	$0.6	$1.8
Return of capital (depreciation)	$0.4	$0.7	$2.0
Opex	$16.0	$15.8	$15.5
Building Blocks Revenue Requirement	$16.8	$17.0	$19.3

***This includes a half year adjustment for the weighted average cost of capital applied in calculating the building block revenues.**

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

	2024-25	2025-26	2026-27
Capex*	$0.1	$0.1	$0.1
RAB (opening value)	$2.8	$2.6	$2.4
WACC (nominal vanilla)	5.68%	5.78%	5.89%
Return on capital	$0.2	$0.1	$0.1
Return of capital (depreciation)	$0.2	$0.2	$0.2
Opex	$4.1	$4.2	$4.1
Building Blocks Revenue Requirement	$4.4	$4.6	$4.5

***This includes a half year adjustment for the weighted average cost of capital applied in calculating the building block revenues.**

Proposed annual revenue requirements

Table 3 below sets out the maximum revenue proposed for System Control and Market Operator. We note that the 2024-25 prices were set based on rolling forward the 2023-24 prices by inflation. This results in a shortfall between actual revenue and the revenue calculated under the building block approach. Consistent with the Commission's decision we propose to recover the shortfall between actual and allowed revenues in 2024-25 by adding the amount to the RAB and depreciating over seven years. This has the effect of increasing revenue in 2025-26 and 2026-27 above the revenue calculated under the building blocks approach. Additionally, the outstanding shortfall will be recovered over the next regulatory period (5 years) resulting in higher revenue than would be calculated under the building blocks approach. This approach help smooths the impact of recovering the shortfall for customers during this regulatory period.

Table 3 – Proposed annual revenue requirements ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	$9.2	$18.4	$20.6
Market Operator	$0.8	$5.2	$5.1
Total	**$10.0**	**$23.6**	**$25.7**

Regulated charges and bill impacts

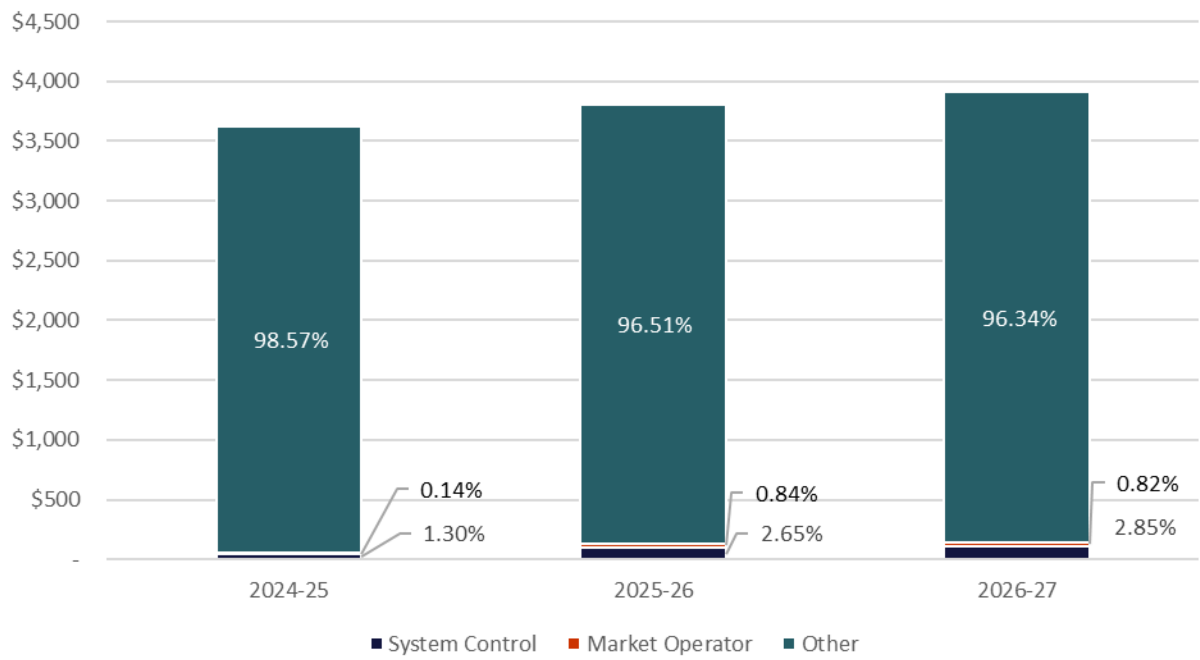
Annual regulated charges are calculated based on the annual revenue requirement divided by the annual forecast energy consumption. **Table 4** identifies the proposed regulated charges which are expressed in nominal dollars. Consistent with the increase in forecast revenue in 2025-26 and 2026-27, we 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	$0.011823	$0.013084
Market Operator	$0.000585	$0.003769	$0.003750

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 1.43% of the annual electricity bill of a small residential customer in the DKPS. Despite the increase in proposed regulated charges in 2025-26, the combined impact in comparison to other charges is relatively low at 3.49%. **Figure 3** shows the change in composition of System Control costs, assuming all other costs in the NT power systems stay constant in real terms.

Figure 3 – NTESMO's contribution to typical Darwin-Katherine residential electricity bill comparison of 2024-25 to 2026-27



1 The NTESMO business

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.

Changes from our Initial Regulatory Proposal

This chapter provides context on our business and our functions and activities. We have updated our proposal to provide more clarity on our functions and activities as required by the Commission's decision. We have also made minor changes to reflect current data.

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 4**. Our functions are set out in Section 38 of the *Electricity Reform Act 2000* (ER Act), the 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]

As System Controller, NTESMO plays a critical role in ensuring the reliability and security of the NT power systems in Darwin Katherine, 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 DKPS I-NTEM, enabling financial certainty for market participants. **Figure 5** illustrates the System Controller's and Market Operator's activities in the NT power systems.

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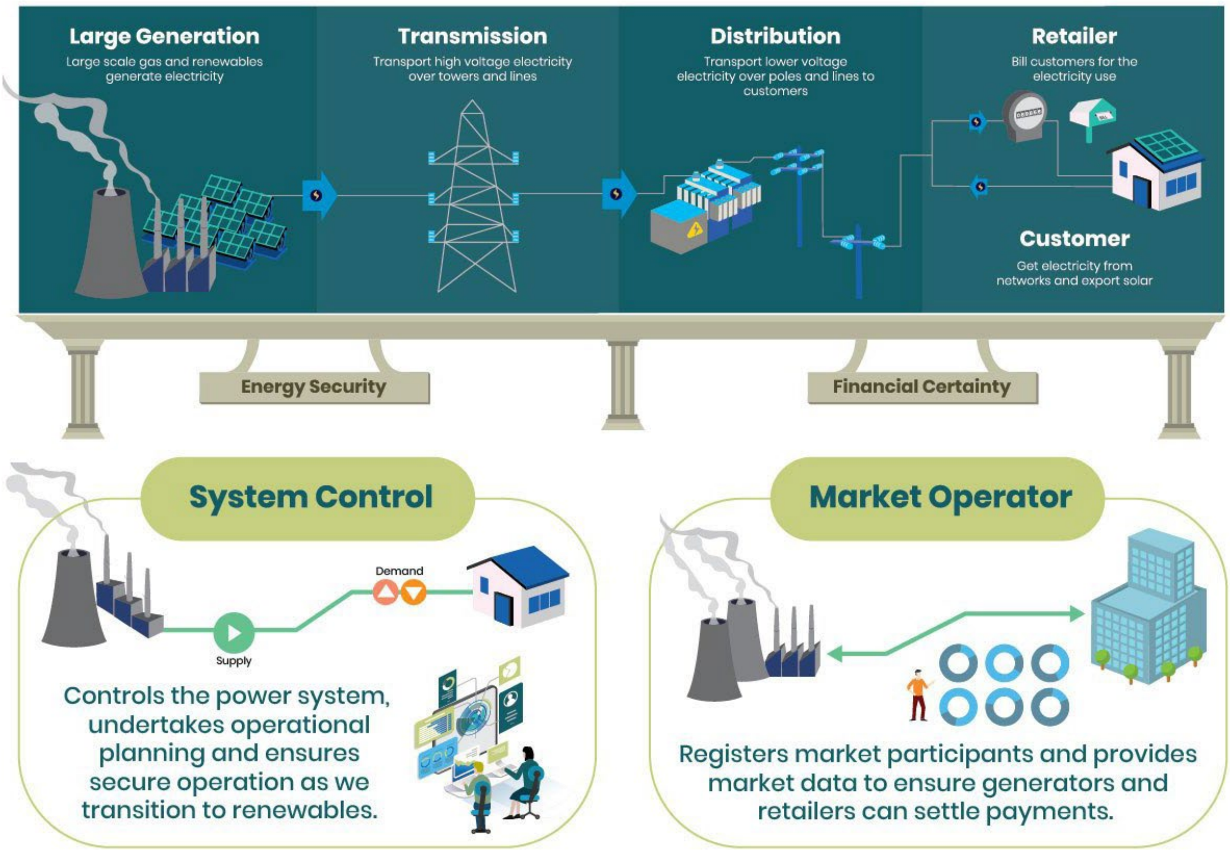
[1] The three electricity systems that Power and Water is responsible for under its System Control Licence are: Darwin-Katherine interconnected system, Alice Springs power system and Tennant Creek power system. The System Control Technical Code is published on NTEMSO's website.

[2] 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's website.

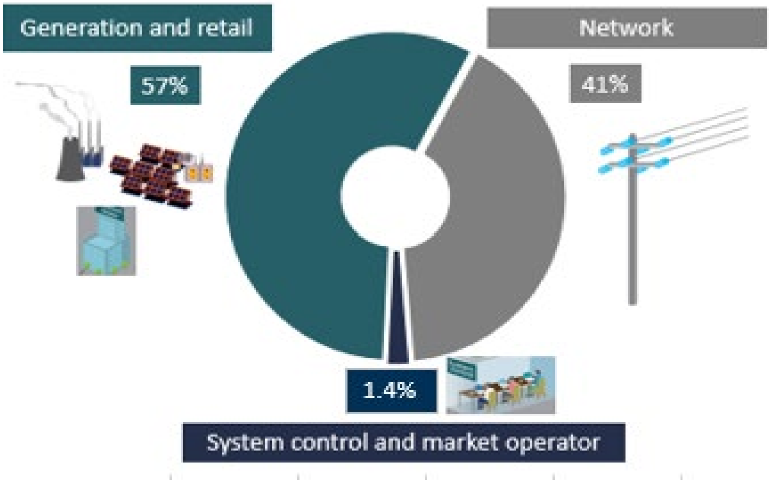
Figure 4: NTESMO function ring-fenced within Power and Water Corporation

Figure 5 – NTESMO's role in the power system



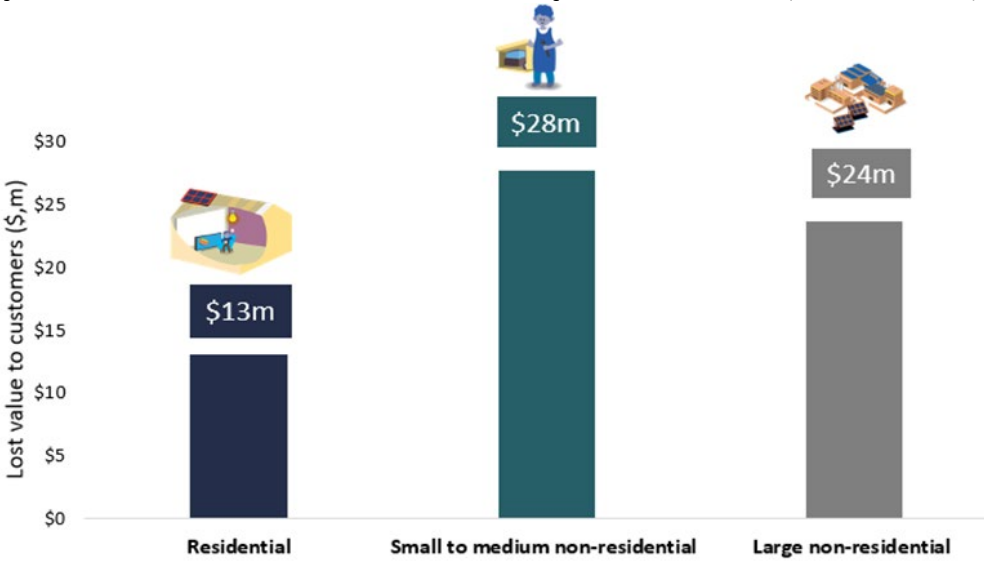
NTESMO charges comprise a very small portion of a customer's electricity bill as illustrated in **Figure 6.** For customers in the DKPS who are not subject to the Electricity Pricing Order[3], the NTESMO charge is currently 1.4% of the total electricity bill.

Figure 6 – 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 DKPS is estimated to impact customers and the economy by more than $65 million due to the loss of value experienced by small and large electricity customers.[4] **Figure 7** demonstrates the loss in value by customer type.

Figure 7 – Loss in value to customers from an 8 hour outage in Darwin-Katherine ($ million, nominal)



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

[4] This has been based on the AER's methodology for deriving a lost value for outages for residential and business customers in the NT. Please see AER, "2023 Values of Customer Reliability Annual Adjustment", December 2023._We have used the 2023-24 benchmarking RIN data for operational performance as a basis for estimating annual consumption by customer type. We have then derived the average 8 hour consumption interval for a customer in kWh. As a final step we have used the $/kWh in the AER's most recent update to derive the dollar basis for loss of value.

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 DKPS.

Some of the specific regulatory obligations required of NTESMO include:

- Section 38 of the ER Act, and clause 1.7.4(b) of the SCTC place clear obligations on NTESMO to maintain a reliable, secure, stable and safe power system.
- SCTC 1.7.4(d) makes NTESMO responsible for establishing operational protocol(s) and arrangements for dispatch and to maintain system security, effectively making NTESMO responsible for ensuring its scheduling and dispatch systems/processes evolve to meet the challenges presented by the additional complexity and volatility of the new intermittent renewable technologies and BESS devices.
- SCTC clause 3.3.2 obliges NTESMO to arrange the required ancillary services (or ESS) to maintain power system security – effective management of ESS including the co-optimisation of dispatch for ESS and energy is becoming increasingly important due to the increasing volatility of supply and demand.
- Specification of System Constraints in accordance with SCTC clauses 3.9.1 and 3.9.2.
- Conduct forecasting in accordance with SCTC clause 3.11.
- SCTC clause 3.11.2 obligates NTESMO to produce short and medium-term demand forecasts and a daily load forecast.
- SCTC clause 6.1 requires NTESMO to undertake short-term operational planning to achieve system security and stability and to ensure the system is operating in an efficient manner.
- SCTC clause 3.7 requires NTESMO to (accurately) assess the overall stand-by availability in the power system and where necessary declare a lack of stand-by generation as well as take necessary measures to restore sufficient standby reserves.
- SCTC clause 4.3 defines the dispatch principles and criteria that need to be considered in the dispatch process, highlighting the complexities involved in forecasting, constraints, treatment of ESS in real-time, commitment and dispatch, decision making for commitment/decommitment, required pre-dispatch and real-time dispatch outputs and determination of market prices, etc.

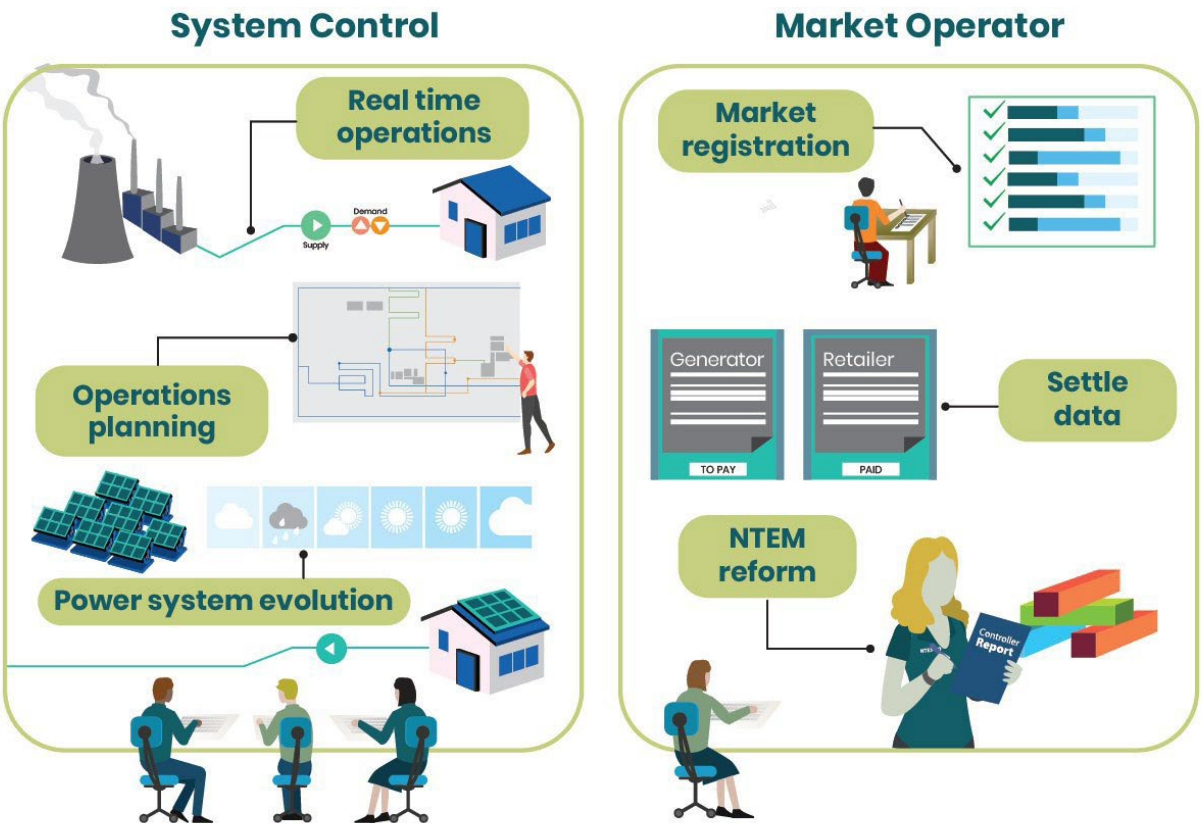
[5] Sections 11.1(a) and 15 of the licence.

[6] Refer to section 1.2 of the SCTC.

1.3 Our functions and activities

NTESMO provides regulated and unregulated services.[7] This proposal only identifies costs for regulated functions. **Figure 8** identifies the key functions we perform as the System Control and Market Operator.

Figure 8 – Functions undertaken by System Control and Market Operator



The functions include:

- 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 the transitional tools and the territory dispatch engine to support growing renewables and new operational procedures. This function also provides forecasting services to allow System Control to make informed real-time operational decisions and manage planned outages to ensure power system security. Reliable forecasting enables more efficient scheduling and dispatch of large-scale generators and considers the significant impact of small-scale inverter- based technologies on the power system.

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

- Market Operations – This involves registering market participants and undertaking analysis on customer energy consumption to enable retailers and generators to settle their bills. This function also supports market participants in the registration, compliance testing, and commercial dispatch processes. This team provides daily generator merit orders to real-time operators based on the offers received from system participants (generators) and ensures dispatch compliance with the issued merit orders. Further, the team oversees the publication of market information in accordance with the approved Market Timetable Procedure (Market Timetable Procedure v1) and publishing daily market data on the web and managing various forecasting models utilised by system controllers.
- Rule Development, Technical and Policy Advice (Market Operator) – This involves providing policy makers with technical advice on issues relevant to our functions.

In our Initial Regulatory Proposal, we provided our activity allocation and obligation mapping at **Attachment 5.1** and advised that it was relevant for the personnel cost forecasts for operating expenditure. We note that the Commission's decision paper stated that CEPA's review of the mapping considered it to be reasonable, however the following points require clarification:

- Generator connection – This activity has been mapped to SCTC clause 6.24; however, it is unclear how this relates to the description of the activity provided.
- System model – This activity has been mapped to SCTC clause 3.3.1; however, it is unclear which item within this clause the activity relates to.
- NTEM development/amend SCTC – This activity has been mapped to both the Market Operator and NTEM reform services. Further, SCTC A6.1 has been mapped to this activity, however, does not appear to relate to the development of NTEM or amendment of the SCTC.
- Market Operator Functions – This activity has been partly mapped to SCTC clause 8.5; however, this statutory reference relates to the System Controller function.

The Commission noted that it would be useful for NTESMO to clarify the specific sub-clauses within the statutory references to which the activity is related. We have updated **Attachment 5.1** to provide the information required by the Commission and have provided additional explanation in **Attachment 5.2**.

2 Regulatory framework

In September 2024, the Commission published its decision paper on the economic regulatory framework to apply to NTESMO's 2024-27 regulatory proposal and future regulatory proposals. We support a clear economic regulatory framework that provides NTESMO with revenue certainty to operate a secure and stable power system to our customer's benefit. Our proposal aligns to the Commission's decision paper.

Changes from our Initial Regulatory Proposal

At the time of submitting our Initial Regulatory Proposal, a prescriptive regulatory framework was not established.

The Commission's decision paper on the regulatory framework establishes a regulatory framework to apply for current and future regulatory periods.

Our Revised Regulatory Proposal aligns with the recent "key decisions regarding the regulatory framework for calculation of system control and market operator charges".[8]

The purpose of this chapter is to confirm that our NTESMO 2024-27 Revised Regulatory Proposal aligns with the Commission's decision regarding the regulatory framework.

2.1 Commission's decision – 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 (Utilities Commission Act) identifies the Commission's requirements in exercising its functions, including making pricing determinations. The Utilities Commission Act does not prescribe a regulatory framework to determine NTESMO's charges.

NTESMO's Initial Regulatory Proposal sought to identify an appropriate regulatory framework and approach to apply to NTESMO's 2024-2027 regulatory proposal. The approach sought to be consistent with, where practical, the NT NER framework for determining revenue allowances for Power and Water's distribution services.

The Commission undertook a round of consultation with stakeholders initiated by a consultation paper on 4 June 2024 that sought feedback on NTESMO's Initial Regulatory Proposal and the economic regulatory framework to determine system control and market operator charges. On 23 September 2024 the Commission published a decision paper which formalised the regulatory framework to be applied to NTESMO's charges.[9]

The Commission noted that NTESMO's 2024-2027 Initial Regulatory Proposal included a complex approach to calculating NTESMO's schedule of charges. Given this, the Commission stated that it was necessary for it to formalise a regulatory framework that promotes efficiency, prevents misuse of monopoly power and protects the interests of consumers while also considering the on-going financial

[8] Commission, 2024-27 Review of system control and market operator charges, decision paper – regulatory framework, 23 September 2024. Refer to the Utilities Commission's website.
[9] Ibid.

viability of NTESMO as a regulated entity.[10] The Commission's decision paper set out the regulatory framework that will apply to the calculation of NTESMO charges for the current and future regulatory periods.

The Commission decided not to approve NTESMO's 2024-2027 Initial Regulatory Proposal as the proposal did not comply with the formalised regulatory framework and needed to address issues identified by the Commission. Additionally, on 23 December 2024 we submitted a Regulatory Proposal that the Commission requested we resubmit due by 28 February 2025. **Figure 9** sets out the key milestones in the regulatory process.

Figure 9 – Key milestones in the regulatory process

22 Dec 2023	–	2024-27 NTESMO proposal submitted
4 Jun 2024	–	Commission published its consultation paper on NTESMO's proposed approach
16 Jul 2024	–	Submissions due on Commission's consultation paper
23 Sept 2024	–	Commission publishes regulatory framework decision, indicating 2024-27 NTESMO proposal is not approved
23 Dec 2024	–	NTESMO regulatory proposal submitted
28 Feb 2025	–	NTESMO resubmits regulatory proposal
Mar – May 2025	–	Commission's assessment of NTESMO regulatory proposal
1 July 2025	–	NTESMO charges commence (estimated timing)

In the sections below, we have aligned our Revised Regulatory Proposal for the 2024-25 to 2026-27 regulatory period to comply with the three key areas of the Commission's decision paper regarding the regulatory approach, model, and timing.

Additionally, the Commission identified areas of our Initial Regulatory Proposal requiring further information and adjustment, including assessment of capital expenditure, recovery of historical expenditure, calculation of building blocks, and the uncertainty mechanism. These are addressed in the relevant chapters to follow.

2.2 Regulatory approach

A regulatory decision specifies the types of controls that are imposed on a monopoly business. Consistent with the Commission's decision paper, we propose to apply a revenue cap for the 2024-27 regulatory period.

Under a revenue cap, the Commission's decision paper establishes a fixed revenue profile for each regulatory year. The allowed revenue is not adjusted for changes in costs, however there are adjustments for under-or over-recovery from year to year. Further, consistent with the Commission's decision paper, revenue can be adjusted for pass through events under the uncertainty mechanism (see section below).

[10] Ibid., p. 54.

2.3 Regulatory model

A regulatory model refers to the calculations underpinning the fixed revenue profile for each regulatory year, and mechanisms to adjust the revenue cap within the period.

Consistent with the Commission's decision paper, we have used the building block model to calculate annual revenue in the 2024-27 regulatory period. In determining the revenue cap, the model considers the following:

- Operating expenditure – Includes all forecast costs that NTESMO pays on a regular basis as part of the day-today delivery of its service(s). It is recovered within year (i.e. on an as-incurred basis).
- Return of capital (depreciation) on the regulatory asset base – Capital expenditure relates to assets that can provide services to customers for a period of many years. The depreciation allowance recovers the cost of capital investment in instalments over an 'asset life'.
- Return on capital of the regulatory asset base – An allowance for a level of return to investors, who provide the regulated firm with financing, to compensate for the cost of the capital made available. This rate of return is known as the weighted average cost of capital (WACC).
- Corporate tax payments – An allowance for tax is forecast based on the size of the other building blocks.

Our proposed building block methodology also includes an uncertainty mechanism and incentive mechanisms to apply to the 2024-27 regulatory period. The uncertainty mechanism recognises that events might occur after the Commission's final decision that materially increase the costs of providing NTESMO's services, and which require an adjustment to the approved revenue. This is discussed further in Chapter 11.

Incentives provide rewards and penalties for NTESMO in relation to costs and performance. While we have notionally included this as part of the methodology, consistent with the Commission's decision paper, no incentive mechanism is proposed to apply in the 2024-27 regulatory period. We note that incentives might be applied in following regulatory periods.

The sum of the above building blocks provides the total allowed (required) revenues of the regulated firm across the regulatory period.

2.4 Regulatory timing

We propose that the 2024-27 regulatory period is for three years commencing from 1 July 2024 and ending 30 June 2027. This is consistent with the Commission's decision paper.

We agree with the Commission that the key reasons for a shorter period are:

- The TEM Reform Program's timing is uncertain, which results in difficulties in making credible assumptions for a longer period.
- In practical terms, there is unlikely to be sufficient time for NTESMO to produce a revised regulatory proposal covering five years, and for that proposal to be adequately reviewed and a final decision on charges made ahead of the 2025-26 financial year.[11]

[11] Ibid., pp. 6 and 7.

2.5 Key inputs and assumptions

Our proposal is based on the following key inputs and assumptions.

Unregulated costs

As outlined in Chapter 1, NTESMO provides several unregulated services 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 electricity network and water businesses, and where we provide settlement functionality for the systems outside of the I-NTEM to Territory Generation.

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.

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 the Revised Regulatory Proposal and will continue to refine this approach for the following proposal. Refer to **Attachment 5.1** for further detail.

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 (DKPS 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.

We applied this approach to actual personnel costs in 2022-23 and forecast personnel costs.

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 largely developed 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 expenditure provides value beyond the years 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 these costs were treated as opex, these costs would be recovered in the year incurred and would result in larger price increases than already forecast.

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 our Revised Regulatory Proposal to determine the proportion of corporate overheads that are capitalised and expensed. Further information is provided in **Attachment 2.2**.

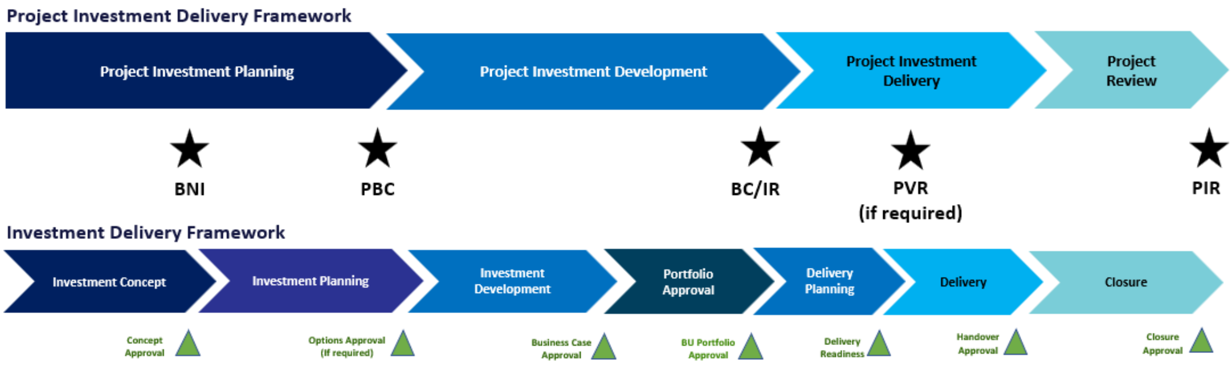
Governance and approvals of expenditure

As part of our Initial Regulatory Proposal, we provided information on the approach to expenditure approvals at that time and relevant to approved expenditure. This approach was termed Power and Water's 'Project Investment Delivery Framework (PIDF) as set out in the Management Standard at **Attachment 2.3** (PIDF). We noted that this provided a robust framework to be applied to our investment decisions.

Consistent with the Commission's decision on unfunded historical expenditures, we have provided evidence of approvals under the PIDF to justify the prudency of proposed historical capital costs that were unfunded in the 2019-24 period (refer to Chapter 7).

We note that a revised governance framework termed the "Investment Delivery Framework" (IDF) was developed and in effect from April 2024, that is, after to our Initial Regulatory Proposal. The Management Standard for the IDF is at **Attachment 2.3** and was applicable to capital expenditure in the 2024-27 regulatory period**. Figure 10** below illustrates the differences between the PIDF and IDF including the artefacts required at the different approval gates. We note that the IDF is applicable and relevant for forecast expenditure in the 2024-27 regulatory period, including the Dispatch Systems discussed in Chapter 6.

Figure 10 – Changes from the PIDF to IDF



Key changes

Separating the stage to:

- Align to the decision point for better accuracy of monitoring;
- Gain better visibility of the pipeline initiatives to enable pre-planning activities
- Improve communication channels

Portfolio Approval

- Approval of Business Unit Portfolio in line with the SCI timings

Separating the stage to:

- Gain better visibility of procurement activities;
- Improve progress reporting to address non-delivery.
- Handover to delivery partners
- Set up delivery for success

- Tightening of closure activities
- Handing over benefits realisation accountabilities

3 Changing landscape

NTESMO is responding to changes in the NT power systems and market. These changes include an accelerated transition from synchronous generating systems to asynchronous renewable generating systems, and an exponential increase in data volumes to settle the market.

Changes from our Initial Regulatory Proposal

This chapter sets out the factors driving a transformational change in our operating environment. We have not materially changed our proposal but provided updates on the Territory Electricity Market reforms (formerly Northern Territory Market reforms) and edited the content.

This Chapter details how NTESMO's operations have been and will continue to respond 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 systems to renewable generating systems and supporting technologies. We are also managing increasing volumes and complexity of data required to settle the market due to the rollout of smart meters, and ensuring we amend the SCTC and provide technical support to the NT Government for regulatory reform.

3.1 Transition to renewable technologies

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

In the NT, the shift commenced a decade ago with households investing in inverter-based PV generating systems. The level of behind the meter PV generating systems has increased over the last 5 years with almost 1 in 4 customers installing small-scale PV generating systems, with a total capacity of 115 MW, and providing approximately 13% of underlying energy consumption. We are also likely to see a surge in dispatchable large-scale solar in the immediate term, with an expected 68 MW of capacity connecting on the DKPS transmission line.

The transition to renewable technologies in all three power systems accelerated due to the previous NT Government's RET of 50% renewable energy delivered by 2030.

Facilitating renewable technologies in the NT

The shift from synchronous generating systems to asynchronous PV generating systems 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. PV generating systems only operate in daytime hours when the sun is shining. The System Controller must continue to ensure sufficient capacity is available to meet demand when PV generated electricity is not produced.
- **Demand volatility** – PV generated electricity depends on sunshine. When there is no sunshine or cloud comes over synchronous generating systems, BESS must meet customer's consumption and system demand. The System Controller must plan for these periods by ensuring there is sufficient generation capacity instantaneously available from non-PV generating systems (considered to be

synchronous generating systems or BESS).

- **ESS** – Synchronous generating systems have inherent physical characteristics that can be relied on to provide ESS such as frequency management, voltage support and system strength. These services cannot be relied on to the same extent when renewable technologies are predominantly meeting demand in the daytime hours, leading to high risk of system-wide events.

We have seen a significant increase in the number of incidents where the system is not secure, in 2023 non-reliability notices were issued for 26 days. By September 2024, this figure increased to 38 non-reliability notice days, reflecting a significant year-on-year rise. We expect the non-reliability notice days to expand as specific thermal facilities are anticipated to retire (or potentially be refurbished) in the next several years. Retirement or refurbishments will impact facility availability which is anticipated to result in the increase in the non-reliability notice days. System reliability modelling undertaken by NTESMO indicates that system reliability is expected to deteriorate.

In the context of the above challenges, NTESMO plays a critical role in evolving and modernising our tools, systems and processes to schedule and dispatch assets optimally and securely.

As synchronous generating systems retire, the NT will require investment in new physical assets including generating systems, BESS and synchronous condensers to ensure sufficient capacity to securely meet supply 24 hours a day and assets that provide ESS. Changes to the regulatory framework will also play a key role in incentivising sufficient investment in new assets and ensuring the market rules supporting scheduling and dispatch functions reflect the changing technology mix and technical characteristics.

Modernising System Control – evolving our processes, systems and tools

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 ESS.

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

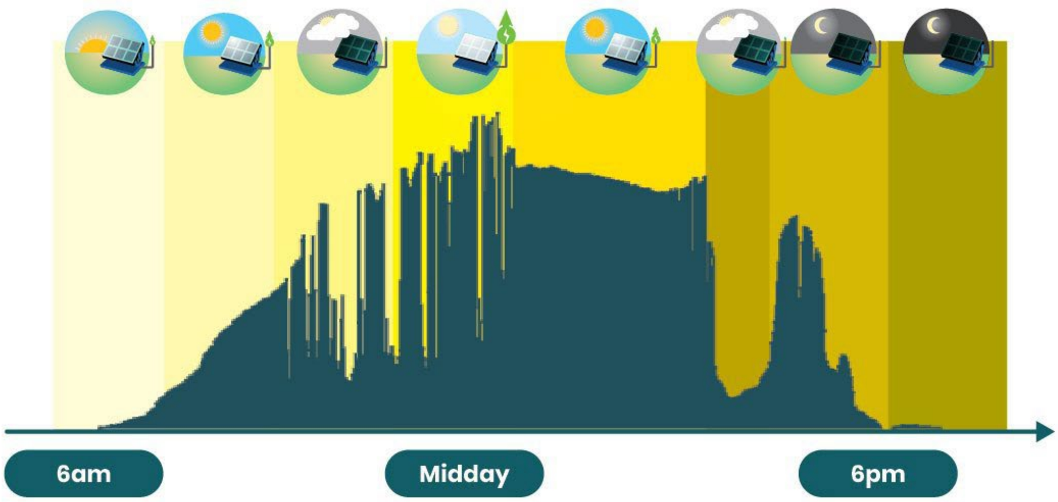
As we transition to a higher penetration of renewable generation, the System Controller will need modern real-time systems to control the existing and new physical assets on the power system. This reflects the increased complexity in decision making in an environment where generation technology is diverse, 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 inverter-based PV generating systems grew significantly in the current regulatory period, supplying an increasing portion of energy demand during the day. However, as seen in **Figure 11**, 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. However, forecasting accuracy of solar generation amounts available for the next day continues to be challenging.

Figure 11 – Solar production on a day with cloud and sunshine



We have also implemented tools to ensure large-scale generators comply with the Generator Performance Standard (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 renewable generating systems (mainly solar farms) and supporting technologies (e.g. BESS and synchronous condensers) in DKPS and to manage issues with growing behind the meter PV generating systems.

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

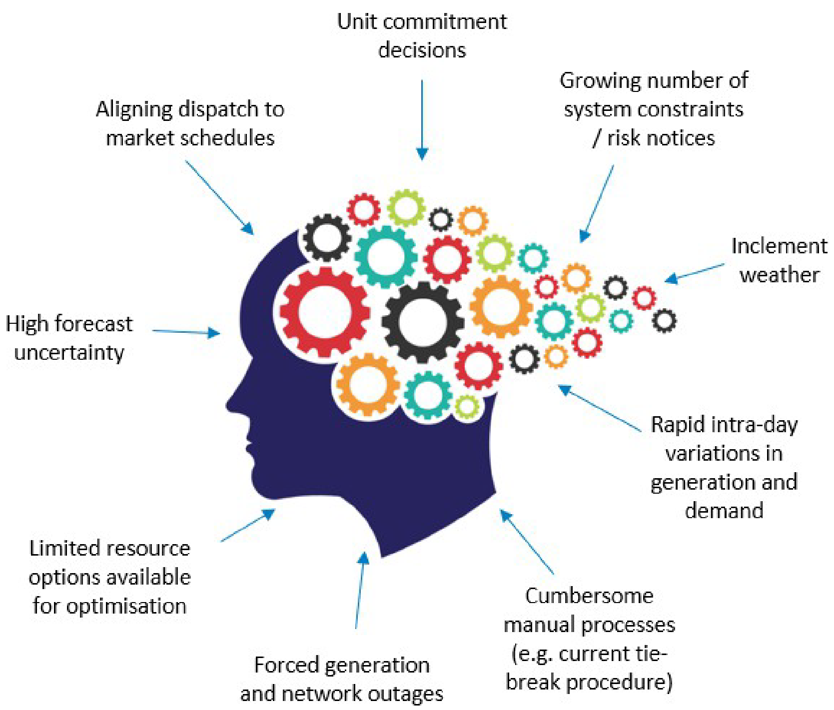
We also see a need to invest in tools that provide greater visibility and response capabilities to ensure adequate scheduling and dispatch of ESS. This reflects that the solar farms connected to the DKPS commenced exporting their generation in 2023-24 and small-scale inverter based- technologies grew, displacing thermal generation that historically have provided a significant proportion of the required ESS to underpin system security.

Territory Dispatch Engine

While the transitional tools we have relied on to date have been effective at managing renewable growth, these are not sufficiently integrated or capable of forecasting for a power system that has a variety of technology types, particularly where many of these are dependent on renewable resources.

In the current and next regulatory period, we have and are facing a step change in large-scale renewable asynchronous generating systems connected to the grid replacing synchronous generating systems as these retire. 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. In the future it will be important to have a dispatch system that can be adapted to accommodate the need to control behind the meter inverter-based technologies. 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 12** below.

Figure 12 – Factors contributing to cognitive overload for System Controllers



The TDE will embed the tools we have developed within an integrated system. The timing of investing in a new system is prudent as:

- 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 generating systems will connect in the current and next regulatory period. This is also validated by recent public tenders seeking to construct 100 MW of large-scale PV generating systems. While the actual numbers are to be finalised, under the current RESIP modelling of 50% by 2030, it is expected that large-scale PV generating systems, and BESS will increase registered capacity by several hundred megawatts and a growth in small-scale PV generating systems from 120 MW to 147 MW.
- Significant investments in new technology – We also expect that new technologies such as synchronous condensers and large-scale BESS will connect to the electricity network in the current regulatory period. Currently, we have limited tools to draw on these physical assets to provide system services such as frequency, voltage and system strength.
- The increased and forecast ongoing take-up of small-scale PV generating systems will result in more intervals where there is insufficient demand to enable synchronous generating systems needed to secure the power system.

3.2 Increasing complexity in meter data for settlement

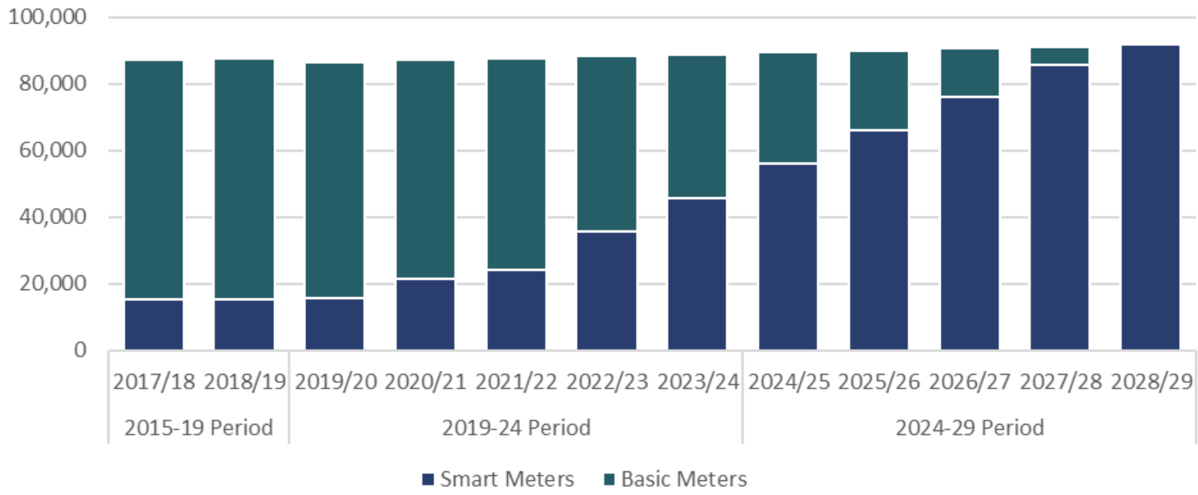
In 2015, the I-NTEM reform required NTESMO to perform a virtual settlement function in the Darwin-Katherine electricity market. A bespoke Excel spreadsheet was developed to calculate energy consumption and issue virtual invoices to retailers and credit notes to generators. This was intended to be a short-term 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 electricity smart meters, a small fraction of the meter population. As at November 2024 we have 44,537 interval meters installed.

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.

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 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 13**.

Figure 13 – Smart meter roll-out forecasts



Further limitations of the Excel spreadsheet basis of settlement included:

- It is not inherently secure and was prone to crashing.
- It was no longer being supported by the vendor, who considered the current system was not designed for long term use with any further development of the system slow and inherently risky.
- It would not support the expected significant rise in metering data stream inputs given it was designed for approximately 1,500 smart meters, which subsequently increased to 16,000 interval meters by 2020, more than 31,000 smart meters by 2023 and 44,537 smart meters in November 2024. It was never anticipated that the bespoke system would be required to manage over 90,000 smart meters by the end of the smart meter rollout by June 2029.
- It did not conduct the required validation to support the data processing required to conduct the market settlements and ancillary (essential) services calculations.
- It did not deliver transparency to customers in the settlement of commercial transactions.
- It would require enhancements to implement the Meter to Cash IT program (introduction of the Market Settlements and Transfer Solution (MSATS) transactions and revised meter data file format).
- It was rudimentary in its design and is not configurable to meet any settlement function design changed anticipated through the NTEM (now TEM) reforms.

Our business case sought to identify potential options to address the issue including through 'commercial off the shelf' or bespoke settlement systems. Based on a review of vendor offerings, we identified that the best option was a 'commercial 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. Like the TDE, the system can be configurable to specific requirements arising from TEM reform.

3.3 Rule Development, Technical and Policy Advice

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.

Many drafting amendments that have not yet been publicly released, but support alignment with the National Electricity Rules and the NTEM (now known as TEM) reforms. In our Initial Regulatory 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 TEM reform process would address the changing landscape and precede the transition. However, the NTEM (now known as TEM) Reform Program was delayed, and we have incurred higher costs to meet our changing circumstances without a cost recovery mechanism in place.

Since our Initial Regulatory Proposal, the TEM Reform Program has been advanced by the previous NT Government. The TEM is designed to create a centralised approach within each of the regulated power system's for determining and procuring services at lowest cost while ensuring system security and reliability requirements are not compromised. Central to the new market design for the DKPS 'public procurement model'. This will centralise the planning and procurement of wholesale electricity services within the DKPS. The previous NT Government also decided to adopt a sole supplier arrangement for the AS and TC electricity systems.

The previous NT Government identified supporting governance arrangements to establish and clarify the roles and responsibilities of different entities required for the TEM. These include:

- Separating NTESMO from Power and Water Corporation into an independent entity to undertake system operations and real time dispatch, central planning and procurement activities, and market settlement functions in line with the new role for NTESMO in the TEM.
- Establishing a new set of NT electricity system and market rules (market rules) that will consolidate the operations of the system and market into a single set of rules for the TEM.
- The Department of Industry, Tourism and Trade (now Department of Mining and Energy) being formally tasked with coordinating policy and market development through administering the market rules.
- Providing the Commission with appropriate regulatory oversight role for maintaining sole supplier arrangements in the Alice Springs and Tennant Creek power systems.

4 Engagement with stakeholders

In developing our initial proposal, NTESMO consulted with key stakeholders on the regulatory framework and key elements of our proposal.

The Commission has also consulted with stakeholders in developing its decision on the regulatory framework.

Changes from our Initial Regulatory Proposal

In our Initial Regulatory Proposal, we described our stakeholder engagement and the feedback we received during our industry forums and in response to stakeholder feedback papers.

For this Revised Regulatory Proposal we have not undertaken further engagement with stakeholders since our Initial Regulatory Proposal as the Commission intends to undertake further consultation.

4.1 NTESMO's engagement approach for Initial Regulatory Proposal

In preparing our Initial Regulatory Proposal, 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.

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 several stakeholders in one-on-one meetings, particularly stakeholders who could not attend the workshop. Two written submissions were received in response to the issues in the consultation paper.

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. 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.

Similar to the first round of consultation, we also held several 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.

4.2 Commission’s engagement on the regulatory framework

In June 2024, the Commission released a Consultation Paper seeking feedback from stakeholders on the approach proposed by NTESMO and the Commission’s initial views or options on that approach. The Consultation Paper sought feedback on matters including the use of a building block regulatory model, the approach to determining allowances for each of the building blocks, the length of the regulatory period, the recovery of historical overspends and true-up of 2024-25 revenue and the approach to calculating regulated charges.

The Consultation Paper posed 21 questions to stakeholders to help guide feedback. The Consultation Paper was open for submissions for a six-week period ending on 16 July 2024. The Commission received submissions from NTESMO, Jacana Energy (Jacana), the Northern Territory Department of Treasury and Finance (DTF) and Territory Generation (TGen).

4.3 Opportunities for further feedback from stakeholders

The Commission noted that it will consult with stakeholders on NTESMO’s regulatory proposal following its receipt. It noted that the focus of the next round of consultation will largely be the proposed revenue requirement and associated system control and market operator charges. Given the Commission intends undertaking consultation, and our proposal aligns with the Commission’s regulatory framework, we considered consulting further with stakeholders in a limited timeframe would duplicate effort and unlikely to benefit our customers.

5 Operating expenditure

We are proposing forecast opex of $59.7 million in the 2024-27 regulatory period. Consistent with the Commission's approach, we have applied a base-step-trend approach to forecast operating expenditure. We are proposing higher operating expenditure than our 2022-23 actuals due to changes in our operating environment that require higher staffing levels and professional fees.

Changes from our Initial Regulatory Proposal

In our Initial Regulatory Proposal, we relied on our actual costs in FY2023 to establish a base year for the purposes of forecasting operating expenditure in the 2024-27 regulatory period and applied step changes.

In this Revised Regulatory Proposal, we have applied the same methodology as set out in the Commission's approach. We have provided further information on personnel, professional services, residual and corporate opex forecasts to address the additional information required by the Commission. We have made corrections and adjustments where new information was available.

Opex relates to costs on non-asset related activities which are recovered on an annual basis. The purpose of this chapter is to provide an overview of our forecast opex for the 2024-27 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 $59.7 million opex over the 2024-27 regulatory period, or approximately $19.9 million annually.

Figure 14 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 $36.0 million, comprising 60.2% of proposed opex. The portion of Power and Water's corporate overheads allocated to NTESMO is forecast at $13.1 million, or about 21.9% of proposed opex.

Figure 14 – Forecast opex by cost category ($m, real 2023-24)

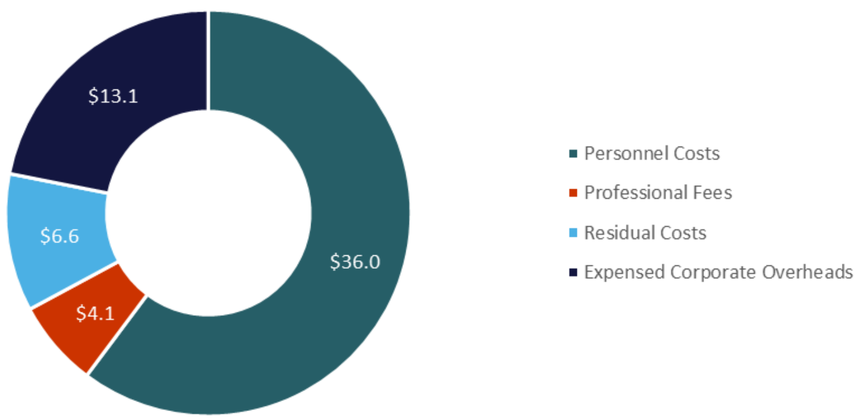
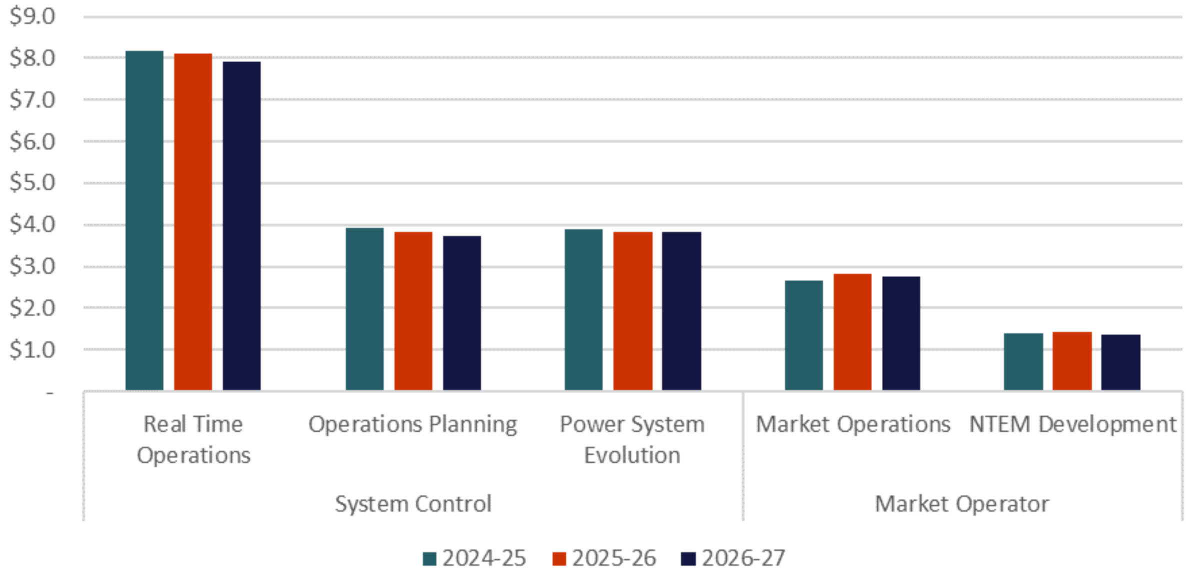


Figure 15 below shows that System Control comprises the majority of proposed opex at 79.1%. The System Control function of power system evolution and real time operations together comprise 59.9% of proposed opex.

Figure 15 – Forecast opex by Function and service ($m real, 2023-24)



5.2 Commission's framework for opex

The Commission's framework aligned with our initial proposal's method to forecast System Control and Market Operator functions by four cost categories – personnel, professional fees, corporate overheads and residual opex.

For personnel, professional fees, and residual opex, the Commission required that costs are mapped between regulated and unregulated activities based on regulatory obligations and activity. Further it required that we apply a base-step-trend method which involves the following steps:

- Determine the base year expenditure.
- Adjust base year expenditure to account for non-recurrent expenditure.
- Adjust to reflect forecast changes in expenditure requirements (step changes)
- Apply an escalation (trend) rate over the regulatory period.

For these three categories of costs, the Commission further considered that the base year is set as the most recent year of audited actual operating expenditure, which is 2022-23. The trend adjustments must relate solely to input costs that are over and above inflation and a zero-productivity factor should be applied.

For corporate overheads, the Commission considered that the Australian Energy Regulator's (AER) approved cost allocation methodology (CAM) and Core Operations CAM should be used to allocate corporate overheads.

Our methodology complies with the Commission's framework for opex. In the following sections we set out our approach for mapping activities to regulatory functions including where we have addressed the Commission's issues. We then identify our forecast costs, methods, and where we have addressed the Commission's issues for personnel costs, professional fees, residual and corporate overhead expenditure.

5.3 Mapping activities to regulatory obligations

We have mapped our activities to regulatory obligations at **Attachment 5.1**. The attachment sets out the function, sub-function, activities undertaken and the reference to our underlying regulatory obligations. We have also allocated the time of our personnel to activities, specifying the amount of time on unregulated activities.

Addressing the Commission's issues

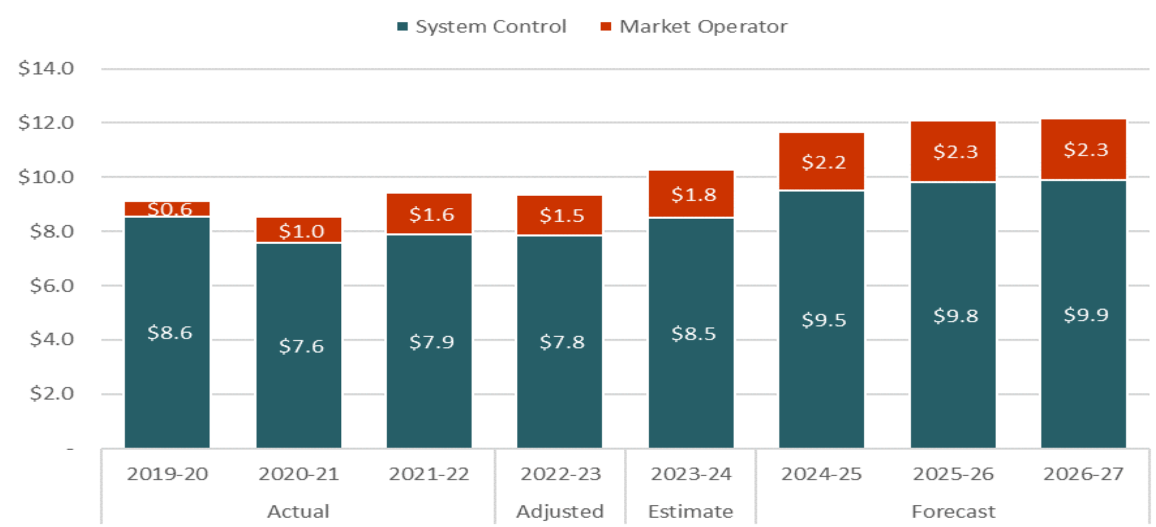
We note that the Commission's decision paper stated that CEPA's review of the mapping considered it to be reasonable, however the Commission required clarification of generation connection, system model, NTEM development and market operator functions. The Commission also noted that it would be useful for NTESMO to clarify the specific sub-clauses within the statutory references to which the activity is related. We have updated **Attachment 5.1** to provide the information required by the Commission and provided further information in section 2.2 of **Attachment 5.2**.

Our general ledger was used as the basis for assigning costs to the system control and market operator functions and differentiating between regulated and unregulated functions. Our statutory accounts are used as the verifiable basis for categorising costs between personnel, professional fees, residual costs and corporate overheads. This is a different approach to our Initial Regulatory Proposal and Regulatory Proposal submitted in December 2024 where we relied on a mapping exercise of our general ledger. Relying on our statutory accounts allows the Commission to verify our base year costs and improves our previous approach.

5.4 Personnel costs

Personnel costs include the labour costs of employees and contractors[12] allocated to System Control and Market Operator. As seen in **Figure 16**, 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 16 – Personnel costs ($m, real 2023-24)



The personnel costs in our statutory accounts is used as the basis for identifying actual costs in the 2022-23 base year. However, it was necessary to make an adjustment to recognise a back-pay for the

[12] Contractors are primarily undergraduates or new graduates.

Enterprise Bargaining Agreement to adjust the base year.

From here, we included the efficient step changes for personnel from 2022-23 including:

- New positions in the next regulatory period, mainly required to perform the Power System Evolution function. This has been based on actual staff in the 2023-24 year and the new staff that have entered the business in the current 2024-25 year. We have not included any new staff from that point. We note that none of these staff will be performing capital activity, with the allowance for labour for the proposed capital projects being set out in the business case. There is no allowance for a vacancy rate required as we used actual data.
- Additional costs from the establishment of two programs with Charles Darwin University for the provision of undergraduate and graduate engineers to address significant resourcing constraints.

To determine the trend amount, we have updated our proposal to use the AER's standard approach, using an average of two weighted price index (WPI) growth forecasts for the utilities industry in the Northern Territory.

Addressing the Commission's issues

The Commission sought further information on the forecast of personnel costs including allocation of personnel to activities, the underlying approvals for the increase in engineering and control room FTE between the 2019-24 regulatory period and current staffing, the source of approvals for additional staff and supporting evidence for on-costs, for proposed additional staff levels, approvals of cost saving information to justify doubling of undergraduates, issues with the adjustment for vacancy rates, capitalisation and escalations rates.

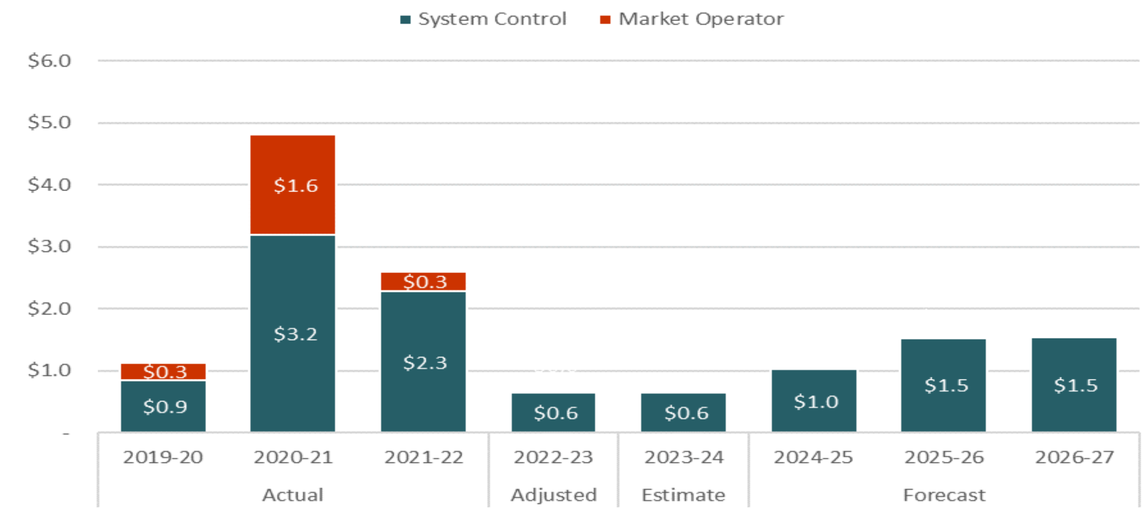
We have provided detailed information on these issues in section 3 of **Attachment 5.2** and made updates to address the issue.

5.5 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 Revised Regulatory Proposal and are described in Chapter 6. The professional fees allocated to opex only include payments for non-asset related activities.

Figure 17 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 17 – Professional fees ($m, real 2023-24)



Our forecast approach involved adjusting the 2023-24 base year to remove professional fees for specific one-off projects that were unlikely to be recurrent. The adjusted 2023-24 base year only included 'business as usual' professional fees. This was on the basis that these costs stay relatively stable on a 'year to year' basis.

The adjusted base year only includes the business-as-usual type professional fees. Going forward, we forecast a step change related to costs higher than the base year from the increase in power system modelling required to assess the impact on power system security resulting from more complex connections and an increasingly diverse power system.[13]

Addressing the Commission's issues

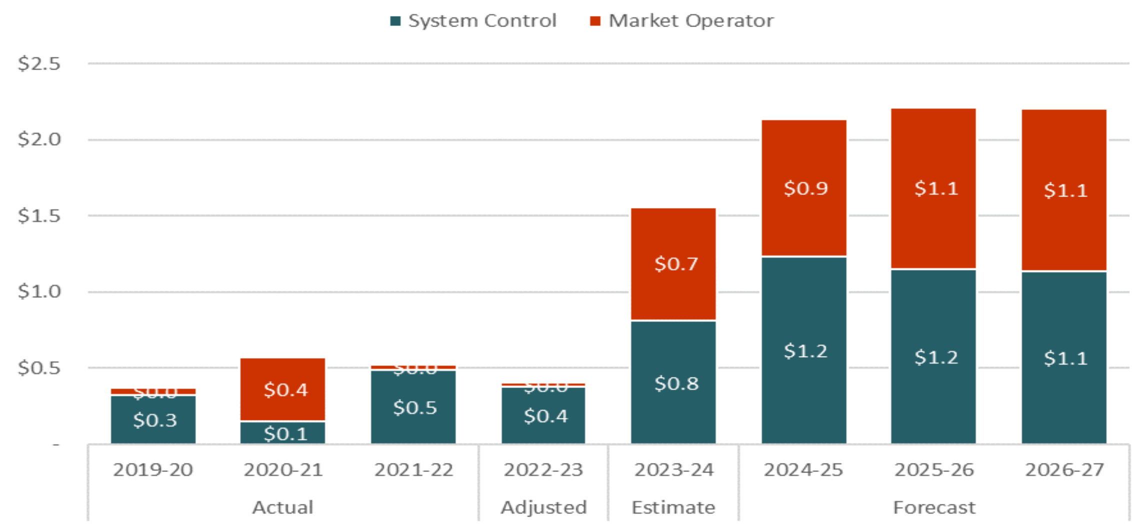
The Commission considered that the rationale for step changes in our initial proposal was high-level and there was no supporting evidence or calculations that detail how the step changes amounts were arrived at. Section 4 of **Attachment 5.2** provides further information and evidence in relation to step changes for professional fees.

5.6 Residual opex

Residual opex relates to ICT services and training. In some cases, these are the direct costs incurred by NTESMO or an allocation of costs within Core Operations. **Figure 18** shows that that other costs will increase compared to actuals.

[13] NTESMO has a regulatory obligation to maintain power system security. The step increase in professional services is to assess the impact of new connections. distributed energy resources (DER) and the expected retirement of synchronous generating system on power system security.

Figure 18 - Residual opex ($m, real 2023-24)



We have adjusted actual costs in the 2022-23 base year to remove non-recurrent costs. We have applied step changes relating to:

- Ongoing vendor service and support costs including additional ICT infrastructure related to the Settlement System.
- The Market Interactions Enablement project which seeks to adopt the Australian Energy Market Operator's (AEMO) Market Settlement and Transfer Solution (MSATS) system and processes.
- Ongoing operational support for transitional tools.
- Regulatory licence fees.

Addressing the Commission's issues

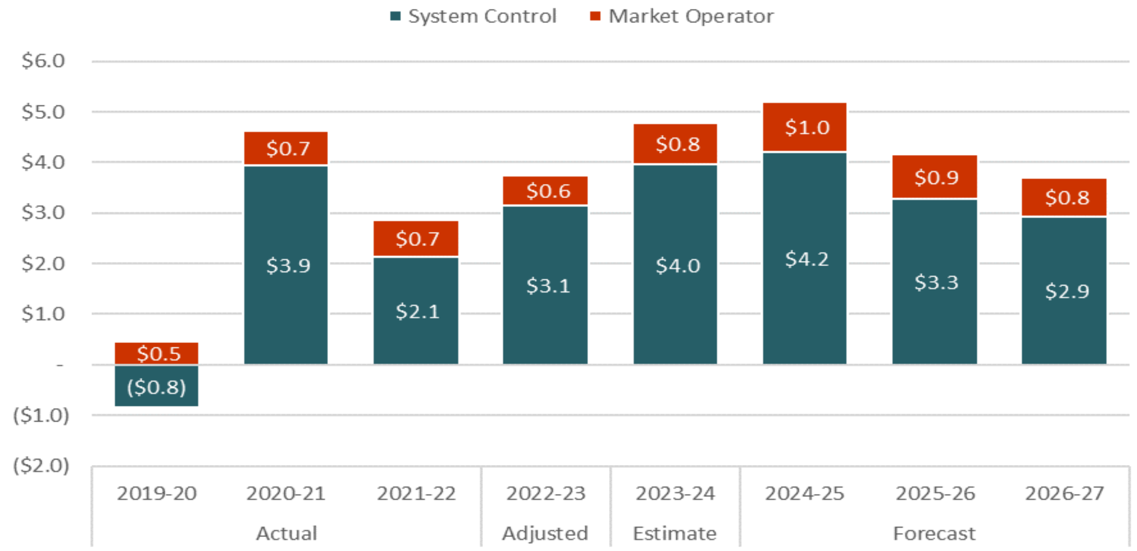
Consistent with the issues on professional fees, the Commission considered that the rationale for step changes in our Initial Regulatory Proposal was high-level and there was no supporting evidence or calculations that detail how the step changes amounts were arrived at. Specifically for residual costs, the Commission noted that this includes step changes relating to the Settlements System and Transitional Tools projects, where an explanation of operating costs and their quantification should form part of the business case for the project. We have addressed the Commission's issues at Section 5 of **Attachment 5.2**

5.7 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.

Figure 19 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.

Figure 19 – Corporate overheads* ($m, real 2023-24)



*Note that in 2019-20 the organisational structure was quite different. The allocation to unregulated activity and adjustments to align to the AER CAM exceeded the total allocation. The underlying total corporate overhead allocation to NTESMO was $3.8 million. This year is not representative of ongoing corporate overhead allocation requirements and is provided for illustrative purposes only.

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

Corporate overheads have increased over time reflecting 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 several 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.

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.

Addressing the Commission's issues

The Commission sought further information on the proportions used to allocate corporate overheads between PWC's business units and their alignment with allocation drivers specified in the AER CAM. It also noted that the forecast FTE numbers used to allocate corporate overhead costs did not align with the FTE numbers used to forecast personnel costs within NTESMO's expenditure forecast model. It also identified other modelling issues that required clarification or updating. Section 6 of **Attachment 5.2** addresses each of the issues raised by the Commission.

6 Capital expenditure

We are proposing forecast capex of $40.2 million to modernise our systems to meet a changing generation mix. The majority of forecast capex is based on TDE having a staged implementation to enhance our capability to dispatch more renewable generation and lower the wholesale cost of electricity due to our increased ability to manage system constraints.

Changes from our Initial Regulatory Proposal

Our Initial Regulatory Proposal included forecast capital expenditure for the 2025-27 regulatory period for evolving transitional tools, a TDE, together with corporate capex and capitalised overheads allocated to NTESMO. In this Revised Regulatory Proposal, we have complied with the Commission's assessment approach for capital projects. We have presented capital expenditure on the TDE project in the Board approved TDE Business Case. Transitional tools capital expenditure is presented in the TDE and Transitional Tools Roadmap Regulatory Business Case, consistent with a Board approved regulatory business case. We have provided a 'best estimate' of costs based on reasonable justification. We have also updated forecast estimates and provided additional information required by the Commission in respect of corporate capex and capitalised overheads.

Capex relates to costs incurred on assets, which are defined as having a useful life of over one year. 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 note that Chapter 7 of our proposal identifies the capex incurred in the 2019-24 period for which we seek retrospective recovery.

In aggregate we forecast that NTESMO's total capex is $40.2 million over the 2024-25 to 2026-27 regulatory period, or approximately $13.4 million each year on average. **Figure 20** shows that the bulk of capex relates to our System Control functions, with the investment in dispatch systems comprising 88.3% of forecast capex in the next regulatory period.

Figure 20 – Forecast capex by driver ($m, real 2023-24)

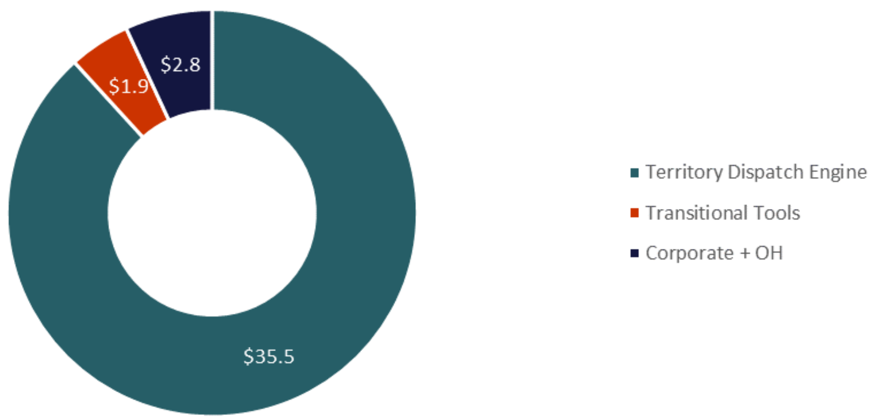


Table 5 sets out the forecast capex by regulatory year for the TDE, Transitional Tools, corporate capex allocated to NTESMO, and the capitalised portion of corporate overheads.

Table 5 – Forecast capex by regulatory year ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
Territory Dispatch Engine	$2.52	$19.88	$13.06	$35.45
Transitional tools	$0.79	$1.15	-	$1.94
Corporate capex	$0.35	$0.43	$0.49	$1.27
Capitalised corporate overheads	$0.27	$0.69	$0.53	$1.49
Forecast capex	**$3.94**	**$22.15**	**$14.08**	**$40.16**

6.1 Commission's framework for capex

Major projects

The Commission's approach for the current and future regulatory periods is to allow an ex-ante allowance for NTESMO's capital expenditure requirement based on a 'best estimate'.

For ex-ante inclusion of capital expenditure in regulatory periods, the Commission identified three broad principles that NTESMO must satisfy.

Firstly, the Commission requires a Board-approved business case that demonstrates the prudency of the proposed project, including its timing, even if the costs in the business case are uncertain. The Commission further clarified on 5 September 2024:

- For the Commission to consider a capital project for inclusion in the RAB, NTESMO needs to evidence that the Power and Water Board has considered the need for the project (and the timing), the costs and benefits of options considered to address the need/issue and decided that the preferred option is to be progressed (subject to funding) as it delivers the highest net benefit.
- While the Commission's preference is for Board approval of the business case that is provided to the Commission, the Commission accepts the Board would not provide its final investment approval to implement the project without the funding. As such, an alternative is for the business case to list with accompanying evidence, the gateway documents (refer to **Figure 3** of **Attachment 2.3**) for the project that have been presented to and endorsed, approved or noted by the Power and Water Board.
- Additionally, the business case should list remaining gateway documents, and the associated approval body (Board and Treasurer) required for the project to be implemented and the expected timing for those endorsements or approvals and any associated dependencies e.g. completion of an RFT process, Commission approval.
- Where no gateway documents have been provided to the Power and Water Board for a project, this should be made clear and explained in the business case submitted to the Commission.
- Beyond matters relating to Board approvals, the Commission notes its expectations in terms of the content of business cases is like those of the AER and exampled by the revised regulatory business cases submitted as part of Power and Water's 2024-29 revised electricity distribution network proposal to the AER.

Secondly, the business case must meet the Commission's minimum requirements for content. Thirdly, the Commission will include an ex-ante capital expenditure allowance for the current regulatory period, based on NTESMO's estimated expenditure, provided the Commission considers that estimate is reasonably justified.

At the end of a regulatory period the Commission will conduct an ex-post end-of-period review of the prudency and efficiency of the actual expenditure of capital projects undertaken during the period. Approved expenditure will be rolled into the RAB. Any difference in the revenue requirement between the ex-ante capital expenditure estimate and ex-post approved capital expenditure will be adjusted for when setting the opening RAB for the next regulatory period.

As identified in Section 6.2, we have complied with the Commission's criteria in respect of our forecast capital expenditure for TDE and Transitional Tools (Dispatch Systems).

Corporate capex and capitalised overheads

In principle, the Commission did not object to the inclusion of corporate capital expenditure; however, it required NTESMO to provide evidence that this expenditure has been allocated appropriately and there is no double counting. We have addressed the issues raised by the Commission in our forecasts for corporate capex and capitalised overheads in Section 6.3.

6.2 Territory Dispatch Engine and Transitional Tools

In our Initial Regulatory Proposal, we provided initial justification of forecast capital expenditure on evolving our suite of transitional tools (Stage 2) projects and developing a new Territory Dispatch Engine. At the time of submitting our Regulatory Proposal in December 2024, NTESMO developed a single regulatory business case titled the NTESMO Territory Dispatch Engine and Transitional Tools Roadmap Regulatory Business Case ("TDE and Transitional Tools Roadmap") this is **Attachment 6.1(b)**. At that time, the Territory Dispatch Engine Business Case (TDE Business Case) was not yet approved.

In February 2025, the TDE Business Case was approved in accordance with Power and Water's project governance framework and is in **Attachment 6.1(a)**. As the TDE Business Case provides the latest cost estimate for the TDE project, our forecast capital expenditure is based on this. Note the TDE Business Case is yet to be approved by the Northern Territory Treasurer as shareholding Minister.

Overview of forecast capex

We are proposing to incur $1.9 million of forecast capex on Stage 2 of the transitional tools (see Chapter 7 for a description of Stage 1) and $35.5 million of forecast capex on implementing Stage 1 of the TDE in the 2024-27 period.

The key driver of the project is the increasing complexity with operating the regulated power systems, particularly the DKPS. This is due to:

- Large scale asynchronous renewable generating systems will displace retiring gas fired synchronous generating systems, leading to the challenges identified in Chapter 3 including capacity adequacy, demand volatility, and reduced levels of ESS.
- Technologies, such as BESS and synchronous condensers, are being introduced to replace reduced ESS provided by synchronous generating systems. This requires new ways to determine the overall system need and the balance of energy and ESS.

In this context, system controllers will be required to review, analyse, schedule and dispatch the various energy and ESS components needed to safely, securely, reliably, and economically operate the power system in real time.

The underlying need for investment is that system controllers will not be able to undertake their power system security functions using the existing manual process and set of transitional tools introduced in the 2019-24 regulatory period. The TDE and Transitional Tools Roadmap sought to provide quantitative analysis of options as set out in **Table 6**.

Table 6 – Options assessed for the TDE and Transitional Tools Roadmap

Option	Description
Option 1 Reliance on Transitional Tools, no TDE	The business will rely on Transitional Tools delivered in 2019-24 and those proposed for delivery in 2024-27. This would result in most scheduling and dispatch processes continuing to be performed on at least a partially manual basis. Increasing amounts of VRE will continue to stretch the cognitive capabilities of system controllers and elongate many of the processes performed daily. Over time this approach will impact OT and require additional resources.
Option 2 Transitional Tools Stage 2 plus TDE Stage 1 delivered in 2024-27 (staged implementation of TDE) **Preferred option**	The business will rely on Transitional Tools delivered in 2019-24 and those proposed for delivery in 2024-27 and the subsequent development of the TDE. Implementation of TDE would be a prioritised partial functionality implementation, with the functionality included for TDE Stage 1 being prioritised to include those functions seen as essential for delivering benefits in the areas of forecasting, real time monitoring, scheduling and dispatch, i.e. those areas most critical to power system operations and security. Areas of TDE functionality for which existing processes are considered adequate in the short-term or are more related to potential market design and outcomes from the ongoing TEM reform process, would be deferred to subsequent regulatory periods. Where possible, this option also focusses on utilising 'commercial off the shelf' (COTS) products, rather than bespoke products that need to be built and customised, with COTS products generally requiring less testing, being more cost effective and quicker to implement. Where automation is not critical, enhanced manual processes will be used to provide the required functionality.
Option 3 Transitional Tools plus fully functional TDE implementation ("big bang approach") in 2024-27	This option uses a hybrid approach to deliver the full functionality of the TDE automating most of the identified functionality within the dispatch environment but using COTS products wherever possible. This option will, nonetheless, still require significant customisation and integration between the systems of each Functional Package. This means the timeline, cost and delivery risks would be greater than the staged implementation approach in Option 2.

We undertook net present value (NPV) analysis that sought to quantify the costs and benefits. Based on the Options Analysis Option 2 is the preferred option. Under option 2, we would implement Stage 2 of the Transitional Tools plus Stage 1 of the TDE which would focus on prioritised functions that are most critical to power system operations and security. Areas of TDE functionality for which existing processes are considered adequate in the short-term or are more related to potential market design and outcomes from the ongoing TEM reform process, would be deferred to subsequent regulatory periods. The key benefits of Option 2 are:

- Enhanced capability to dispatch more renewable generation and lower wholesale cost electricity due to the superior ability to manage system constraints.
- The reduction in the increased quantum of required resources to operate a manually orientated system control process.

The scope of the works include Stage 2 of the Transitional Tools include the Demand Forecast Tool Stage 2 (January 2025), Proportional Dispatch Tool (April 2025), Contingency Frequency Control Ancillary Services Tool (June 2025) and Real Time System Security Monitoring Tool (November 2025).

The functional design TDE stage 1 is based on the regulatory obligations of NTESMO in the SCTC and the Secure System Guidelines. The design of TDE stage 1 has been reviewed against regulatory obligations, benefit simulation modelling, power system operating challenges, design decisions and Power and Water's governance processes, including procurement, investment decision-making and approval requirements. Stage 2 of the TDE will be subject to the TEM Reform Program, for inclusion in the 2027-

32 regulatory submission. The design of the TDE in stage 1 will support configurations required for the TEM Reform Program. As noted below, our budget and costs are based on best estimates.

Addressing the Commission's issues

As set out in section 6.1, the Commission required evidence that major projects such as the TDE and Transitional Tools meet the criteria for inclusion in the ex-ante capital expenditure allowance. We have submitted the following evidence:

- Board endorsed business case - As part of our Revised Regulatory Proposal we have submitted the TDE Business Case (**Attachment 6.1(a)** and TDE and Transitional Tools Roadmap Regulatory Business Case (**Attachment 6.1(b)**). Additionally, we have included a summary of the relatively minor variations in the numbers for the TDE project in the TDE Business Case and TDE and Transitional Tools Roadmap Regulatory Business Case in **Attachment 6.1(c)**.

  In submitting this Revised Regulatory Proposal, in accordance with our IDF governance, the Board has approved the TDE Business Case after considering the need for the project (and the timing), the costs and benefits of options considered to address the need/issue and decided that the preferred option is to be progressed (subject to funding) as it delivers the highest net benefit. The project is at a stage in our IDF governance where it has been submitted to the Northern Territory Treasurer.

- Minimum contents - Appendix A of **Attachment 6.1(b)** identifies how we have responded to the Commission's minimum requirements for content.

- Best estimate reasonably justified - Our proposed costs submitted in this Revised Regulatory Proposal are based on a 'best estimate'. The costing methodology for the transitional tools projects was based on a structured approach leveraging historical cost data from the previous transitional tools projects and requested quotes from perspective suppliers. The TDE costings are based on the detailed vendor proposal documentation resubmitted post tender due diligence negotiations. The allocated hardware cost estimate was produced by the perspective hardware design and install consultancy who participated in the applicable vendor due diligence workshops. Section 11 of **Attachment 6.1(b)** provides more information.

6.3 Corporate capex and capitalised overheads

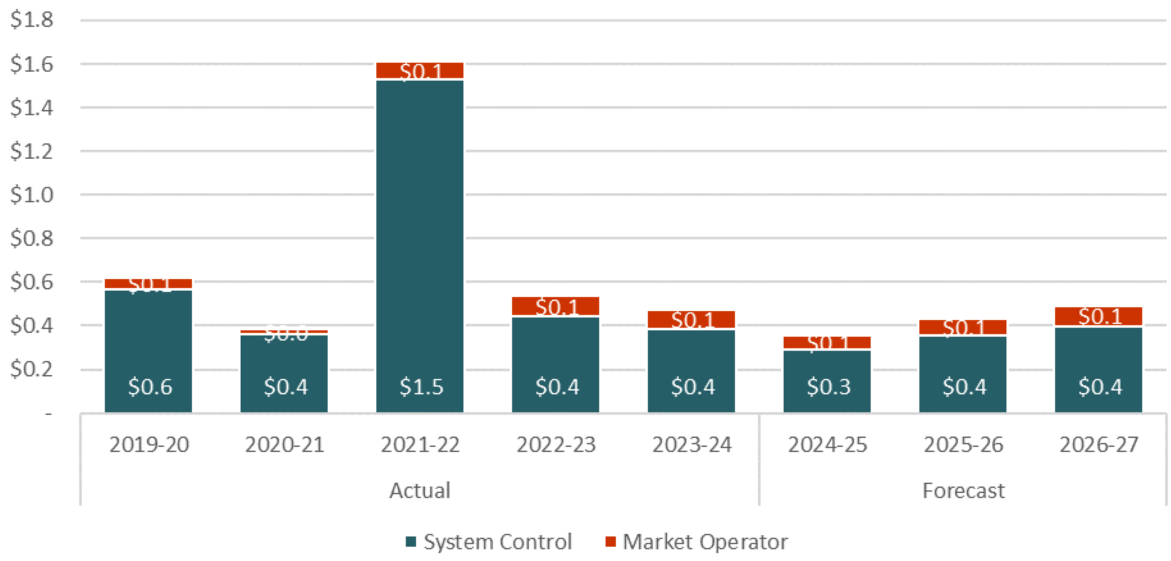
Corporate capex

We are proposing forecast capex for indirect costs allocated to NTESMO including corporate capex and capitalised overheads. As a multi-utility, Power and Water incurs capex on corporate, non-network assets that are shared across business functions. This included ICT systems, corporate property, and fleet.

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.

Figure 21 sets out the actual, estimate and forecast corporate capex. The drivers of investment in corporate capex relate to ICT systems that are shared across Power and Water's business units including Asset Management, Financial Management and Billing systems. These 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

Figure 21 – Corporate capex ($m, real 2023-24)

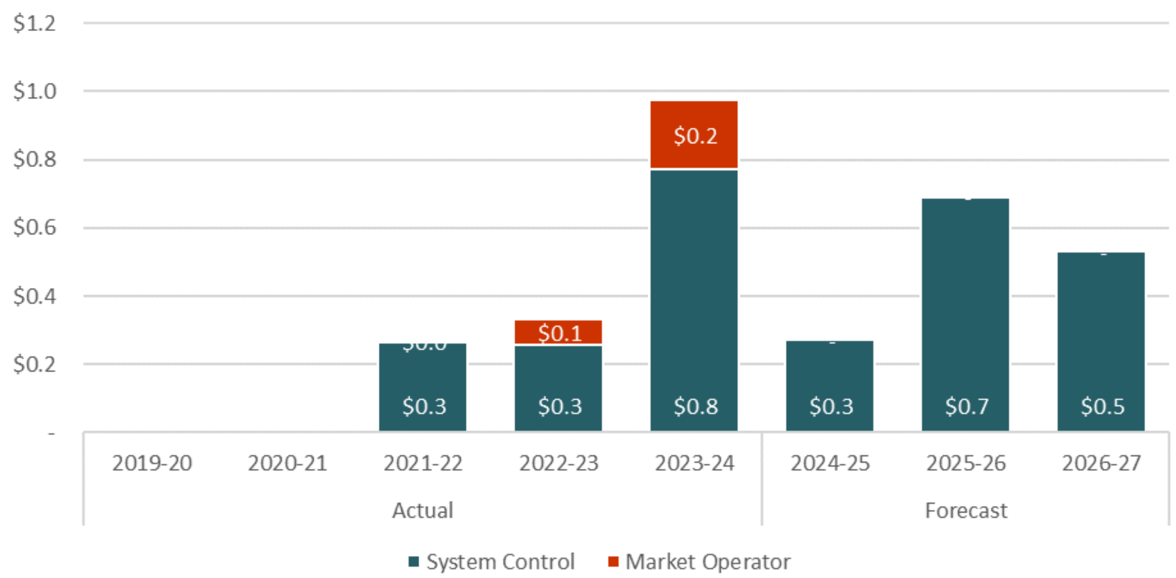


Capitalised overheads

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. **Figure 22** sets out the actual, estimate and forecast corporate capex for capitalised wages.

Figure 22 – Actual and forecast capitalised corporate overheads



Addressing the Commission's issues

As noted in section 6.1, the Commission did not object to the inclusion of corporate capital expenditure. However, it sought further information from NTESMO in respect of both corporate capex and capitalised overheads which we address below.

Information to demonstrate that there is no double counting

The Commission required NTESMO to provide evidence that this expenditure has been allocated appropriately and there is no double counting. In this respect, we note that corporate capex relates to projects that have been through the relevant governance framework and relates to a specific asset. Capitalised overheads relate to non-direct costs that are not related to a specific asset.

We also note that section 6.1 of **Attachment 6.1(a)** expressly clarifies the best estimate of the TDE project costs and section 11 of **Attachment 6.1(b)** clarifies the Transitional Tools project costs). **Attachment 6.1(b)** also expressly clarifies that the budget estimates do not incorporate corporate overhead allocations and illustrate the direct costs associated with each of the project elements.

Link between corporate capex and NTESMO's business requirements

The Commission considered that NTESMO's regulatory proposal needs to provide more detail on the corporate capital expenditure projects that form part of corporate capital, in particular, PWC's New Operating Model initiative and other ICT projects. NTESMO's proposal needs to link these projects to NTESMO's business requirements and/or regulatory obligations. For example, NTESMO needs to demonstrate how the Meter to Cash and revenue assurance programs are relevant to and will yield benefits for NTESMO.

We note that the introduction of Velocity, under the Meter to Cash project, will replace Power and Water's aging retail management system (RMS). The new system implementation will enable data to be compatible with the requirements of Market Settlement and Transfer Solutions (MSATS) where data can be sent and received directly to MSATS. The overall corporate investment in an industry platform will help streamline data and provide efficiencies in settling market transactions and with retailer interactions.

In relation to the Operating Model, we note that this was a means of ensuring that Power and Water had the most efficient structure across all its services including NTESMO. In particular, the operating model streamlines corporate support services, and this would be expected to have a consequential impact on NTESMO's costs through corporate overheads. Further information is set out in **Attachment 6.2**.

Corporate capex allocations

The Commission noted that CEPA were unable to locate the calculations underlying the allocation of corporate capital expenditure to the system control and market operator functions. **Attachment 6.2** provides the underlying calculations required by the Commission.

Capitalised corporate overheads

While the Commission accepted the principle of capitalising a portion of corporate overheads, it raised issues with the allocation application including using full time equivalent proportions and the lack of alignment to NTESMO's forecast personnel costs. We have addressed this issue in Chapter 5 of our proposal, and our forecast reflects the updated values.

7 Recovery of unfunded historical costs

During the previous regulatory period NTESMO responded to the challenges of a rapidly changing power system. The Commission's 2019-24 determination did not provide funding for this transition. Although unfunded, we developed new tools and processes to support the transition while maintaining system security and efficient dispatch. We propose to roll-forward the depreciated value of investments in systems that can demonstrate enduring value to our customers in the current regulatory period.

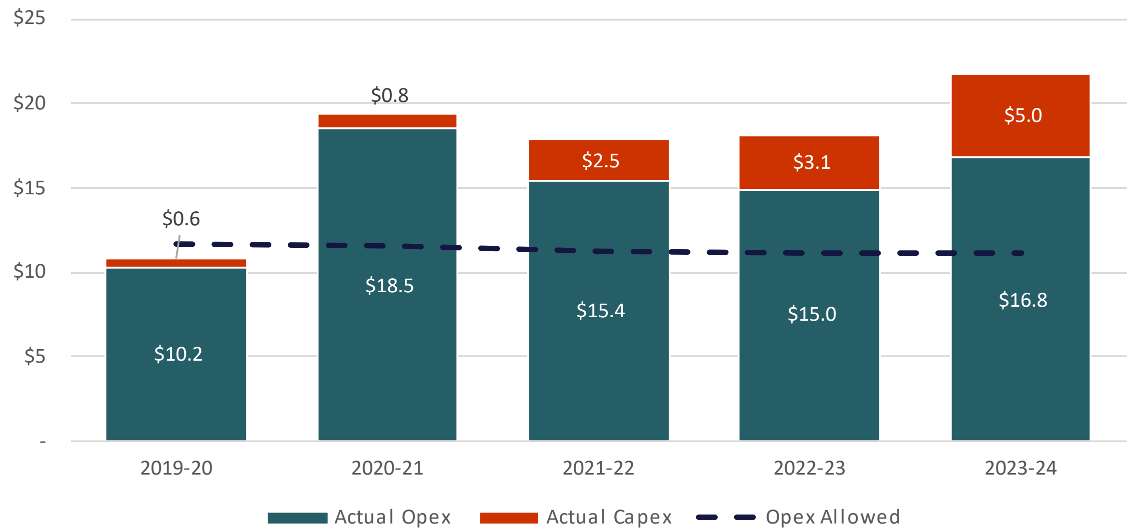
Changes from our Initial Regulatory Proposal

Our Initial Regulatory Proposal proposed recovery of a subset of unfunded costs in the 2019-24 regulatory period. We included both operating and asset costs that we considered were prudent, efficient, and provided an enduring benefit to customers.

In this Revised Regulatory Proposal, we have complied with the Commission's decision on the regulatory framework regarding the inclusion of historical costs, the treatment for revenue calculations and excluding historical operating expenditure. We have proposed recovery of actual capital expenditure for Transitional Tools, Settlements System and TDE projects and corporate capex where the expenditure was necessary and efficient.

In the 2019-24 period, we spent $19.1 million more operating expenditure and $12.1 million more capital expenditure compared to the allowance set by the Commission in its determination as seen in **Figure 23**.

Figure 23 – Difference between actual costs and Commission's allowance for System Control and Market Operator combined ($m, real 2023-24)



The additional expenditure was in response to the rapid changes in NTESMO's operating landscape. 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 Commission's last determination, they were critical to fulfil our legislated role. If these were deferred, customers would have faced increased risks of system events[14] and the NT would be on a slower pathway to connecting large-scale renewable generating systems.

In our Initial Regulatory Proposal, we sought recovery of a subset of operating and capital expenditure costs that related to new events in the period, that had evidence of prudency and efficiency, and which had enduring value for customers. We have updated our Revised Regulatory Proposal in light of the Commission's decision.

7.1 Complying with the Commission's decision on previous overspends

The Commission's decision establishes a framework for the recovery of previous overspends:

- Historical overspend on operating expenditure – We have complied with the Commission's decision that there will be no recovery of operating overspend from the 2019-24 regulatory period with these costs to be borne by NTESMO.
- Historical overspend on capital expenditure – We have complied with the Commission's decision that allows 'approved' capital expenditure from the 2019-24 regulatory period to be added to the RAB and depreciated using standard asset lives. We have also complied with the Commission's decision that there will be no recovery of depreciation or return on capital (until the beginning of the 2024-27 regulatory period) with these costs to be borne by NTESMO. Chapter 8 provides more details on the opening RAB.

In respect of 'approved' capital expenditure from 2019-24, the Commission has indicated its expectation that evidence can be provided of Board approval for the capital expenditure. The following provides evidence of the approvals provided for the capital expenditure in accordance with Power and Water's relevant governance framework, which is discussed at section 2.5 of Chapter 2 of this Revised Regulatory Proposal.

7.2 Proposed capital projects to be included in RAB

Table 7 identifies the historical capital expenditure we propose to seek retrospective cost recovery. We consider these projects meet the Commission's guidelines on approved capital expenditure to be added to the RAB.

Table 7 – Capex seeking retrospective recovery ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
Settlements System	$0.0	$0.2	$0.0	$1.1	$1.4
Territory Dispatch Engine (TDE)	-	$0.2	$0.3	$0.9	$1.8
Transitional Tools	-	-	$0.3	$0.3	$0.3
Total	**$0.0**	**$0.5**	**$0.7**	**$2.3**	**$3.5**

These projects are discussed in detail in the sections below.

[14] System events range from system black or restart events, however, also include other contingency events whereby there is an involuntary loss of supply to consumers (i.e. there has had to be an under-frequency load shed) to ensure that the system could be stabilised and returned to a reliable operating state. There is clear evidence of an increase in the frequency of these events that are adversely impacting customers and there is evidence that these will increase without having more tools to support scheduling and dispatch of these reserves.

7.3 Settlements System

The Commission's decision paper identified its initial assessment of the Settlements System project, found it was sufficiently justified and relevant to the functions of the market operator and identified several issues with **Attachment 7.2** - The Settlements System Compliance Summary included with the Initial Regulatory Proposal.

The Commission also noted NTESMO needed to provide evidence of Board approvals for the settlement system project. To address this **Attachment 7.2** provides more information about the project governance framework under which the settlement system project was approved and provides further details on the settlement system capital expenditure. Importantly, when the settlement system project commenced it was classed as a Category B project under the IDF governance framework, which does not require the business case to be signed by the Power and Water Board.

7.4 Transitional Tools

The Commission's decision paper did not comment on the justification of the transitional tools historical spend, however noted that transitional tools capital expenditure incurred during the 2019-24 regulatory period can be added to the opening RAB for 2024-25 if they were approved.

Attachment 7.1 - Transitional Tools Compliance Summary provides more information about the transitional tools' projects approved and delivered during the 2019-24 regulatory period.

7.5 Territory Dispatch Engine

The project referred to as the 'Territory Dispatch Engine' in this Revised Regulatory Proposal initially commenced during the 2019 to 2024 regulatory period. Capital expenditure during the previous regulatory period is related to the key governance gateway milestones met, including the business needs identification, preliminary business case, final business case, and project variation request. These costs are not recurring beyond the approval of the final business case, and consistent with the Commission's decision paper, the proposed expenditure can be capitalised where NTESMO can demonstrate the project has an enduring benefit beyond the year in which the expenditure occurred, and its prudency and efficiency is demonstrated.

The Commission's decision paper noted that approved historic capital expenditure from the previous regulatory period can be added to the 2024 opening RAB and depreciated using standard asset lives if the Commission approves the expenditure.

Attachment 7.3 – Retrospective costs for the investment in the Territory Dispatch Engine provides further information about the prudency and efficiency of the proposed historic capital expenditure.

7.6 Corporate capital expenditure

The Commission's decision paper confirms the depreciated cost of historic (2019-24) corporate capital expenditure will be included in the opening RAB for 2024-25, suitable evidence is required in the same manner as is required for the forecast values of corporate capital.

Corporate capital expenditure incurred during the 2019-24 regulatory period is included. **Attachment 6.2** includes the actual corporate capex incurred in 2019-20 to 2021-22 consistent with our reporting methods for the AER RIN. We have included estimates of corporate capex for 2022-23 and 2023-24 consistent with the model presented to the AER for our network regulatory proposal.

8 Establishment of opening RAB

Consistent with the Commission's regulatory model we have established an opening asset base to apply from 1 July 2025. The calculation reflects the depreciated historical capital expenditure in the 2019-24 regulatory period that has enduring value to our customers in the next regulatory period.

Changes from our Initial Regulatory Proposal

Our Initial Regulatory Proposal proposed a regulatory model that established an opening regulatory asset base (RAB) as at 1 July 2025. We had proposed that the opening RAB reflect the depreciated costs of historical capex prior to 1 July 2019, a subset of unfunded capital expenditure incurred in the 2019-24 period including capital projects, corporate capex, and capitalised corporate overheads.

Our Revised Regulatory Proposal reflects the Commission's decision. In calculating the opening RAB, we have excluded historical capex prior to 1 July 2019 consistent with the Commission's decision. We have also excluded capitalised corporate overheads on the basis these do not relate specifically to an approved capital project. We have also excluded the Alice Springs Future Grid project, and updated values for other capital projects in the 2019-24 period consistent with Chapter 7 of our proposal.

The purpose of this Chapter is to identify the method and value for deriving the opening asset base of the RAB consistent with the Commission's decision.

8.1 Commission's decision on establishing a 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 Commission's decision on a regulatory framework included the concept of a RAB to establish return on and of investment. The Commission decided that the opening RAB, as at 1 July 2019 will be set to zero.

8.2 Roll forward methodology

Power and Water is seeking to apply a roll forward methodology consistent with the Commission's approach to establish an opening asset base as at 1 July 2025. The method involves developing a separate RAB for System Control and Market Operator using the same approach as set out below:

- Establishing a RAB value of zero at 1 July 2019.
- Consistent with Chapter 7, identify the actual capex in the 2019-24 period that can be added to the RAB as at 1 July 2025.
- Roll forward the RAB value for each regulatory year by including actual capex and regulatory depreciation to derive a closing asset base in each year of the 2019-24 period. Where regulatory depreciation reflects straight-line depreciation net of inflation on opening RAB as is consistent with the AER PTRM modelling approach.
- Use the closing RAB value in 2024-25 to derive an opening asset base value as at 1 July 2025, noting this is adjusted for inflation.

Actual capex

In Chapter 7, we identified actual direct and corporate capex incurred in the 2019-24 period as set out in **Table 8** 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 8 – Actual capex ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	$0.6	$0.6	$2.2	$1.7	$2.5
Market Operator	$0.1	$0.2	$0.1	$1.2	$1.5
Total	**$0.6**	**$0.8**	**$2.3**	**$2.9**	**$4.0**

Regulatory depreciation

The regulatory depreciation is deducted from the actual capex to derive a closing RAB for each regulatory year. Consistent with the Commission's decision, we have applied straight-line depreciation and AER standard asset lives when calculating regulatory depreciation. We have applied the AER's approach to calculating the depreciation allowance including netting off inflation from the straight-line depreciation. **Table 9** identifies the depreciation profile.

Table 9 – Regulatory depreciation ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	-	($0.05)	($0.10)	($0.25)	($0.40)
Market Operator	-	($0.01)	($0.03)	($0.03)	($0.13)
Total	**-**	**($0.06)**	**($0.12)**	**($0.28)**	**($0.54)**

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 10**.

Table 10 – Closing RAB in 2019-24 period ($m, real 2023-24)

	2019-20	2020-21	2021-22	2022-23	2023-24
System Control	$0.6	$1.1	$3.2	$4.7	$6.8
Market Operator	$0.1	$0.3	$0.4	$1.5	$2.8
Total	**$0.6**	**$1.4**	**$3.6**	**$6.2**	**$9.6**

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 for each year of the 2024-27 period is based on a building block approach consistent with the Commission's decision. This includes an allowance for return on and depreciation of the regulatory asset base, and operating expenditure allowance.

Changes from our Initial Regulatory Proposal

We had proposed that a revenue cap apply to the 2024-27 regulatory period based on a building block approach.

Our Revised Regulatory Proposal is aligned to the Commission's decision to apply a revenue cap including the building block components and calculations. We have updated our revenue calculations for consequential amendments to the opening RAB, forecast opex and forecast capex. We have also updated the value of the rate of return to comply with the Commission's approach.

The Commission's decision identified a regulatory approach and model that will require a decision on the maximum revenue that we can recover for each year of the regulatory period through our regulated charges. Our proposed approach complies with the Commission's decision:

- The establishment of an opening RAB value as at 1 July 2025, as set out in Chapter 8.
- A return on and depreciation on the value of the regulatory asset base calculated for each year of the 2024-27 regulatory period. The RAB is based on forecast capital expenditure set out in Chapter 6 and the forecast regulatory depreciation related to capital expenditure.
- Forecast opex for each year of the regulatory period as set out in Chapter 5.
- An estimate of corporate tax liability, which is zero for the 2024-27 regulatory period. 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.

The above steps generate a forecast of the building block allowance and are discussed in Section 9.1. Sections 9.2 and 9.3 discuss the adjustments to the building block allowance to account for the shortfall in revenue in 2024-25. The 2024-25 prices were set based on rolling forward the 2023-24 prices by inflation. This results in a shortfall between actual revenue and the revenue calculated under the building block approach.

Consistent with the Commission's decision we propose to recover the shortfall between actual and allowed revenues in 2024-25 by adding the amount to the RAB and depreciating the shortfall over seven years. This has the effect of increasing revenue in 2025-26 and 2026-27 above the revenue calculated under the building blocks approach.

9.1 Building blocks for 2024-25 to 2026-27

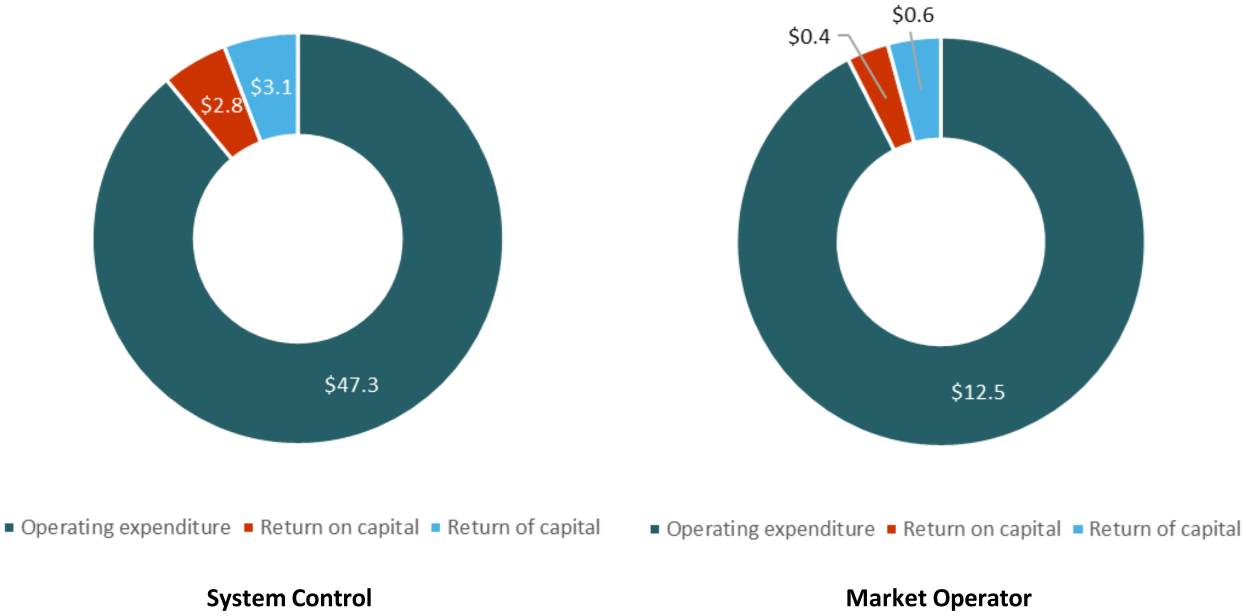
In this section, we discuss the calculations and inputs for each of the building blocks used to estimate forecast revenue for the next regulatory period. The total sum of the building blocks for each regulatory year for System Control and Market Operator is identified in **Table 11**.

Table 11– Building block forecast for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
System Control	$16.8	$17.0	$19.3	$53.1
Market Operator	$4.4	$4.6	$4.5	$13.5
Total	**$21.2**	**$21.6**	**$23.8**	**$66.6**

Figure 24 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 24- Breakdown of System Control and Market Operator revenue for 2024-25 to 2026-27 ($m, real 2023-24)



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 12** identifies the forecast opex allowance in nominal dollars for System Control and Market Operator.

Table 12 – Operating expenditure allowances ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
System Control	$16.0	$15.8	$15.5	$47.3
Market Operator	$4.1	$4.2	$4.1	$12.5
Total	**$20.1**	**$20.0**	**$19.6**	**$59.7**

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 13.** The impact of the revenue shortfall in 2024-25 (refer to section 9.2) is included in the opening RAB values in 2025-26 and 2026-27.

Table 13 – Value of opening RAB ($m, real 2023-24)

	2024-25	2025-26	2026-27
System Control	$6.8	$10.1	$31.6
Market Operator	$2.8	$2.6	$2.4
Total	**$9.6**	**$12.7**	**$34.0**

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.

We have complied with the Commission’s approach to use the AER’s WACC for Power and Water’s electricity network business to calculate the return on capital. The values we have applied for both System Control and Market Operator are set out in **Table 14**. The values are in nominal dollars.

Table 14 – WACC parameters

	2024-25	2025-26	2026-27
Return on equity	7.91%	7.91%	7.91%
Return on debt (trailing average portfolio)	4.19%	4.36%	4.54%
Nominal vanilla WACC	5.68%	5.78%	5.89%

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 15**.

Table 15 – Return on allowances for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
System Control	$0.4	$0.6	$1.8	$2.8
Market Operator	$0.2	$0.1	$0.1	$0.4
Total	**$0.5**	**$0.7**	**$2.0**	**$3.2**

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 16** 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 16 – Return of allowances ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
System Control	$0.4	$0.7	$2.0	$3.1
Market Operator	$0.2	$0.2	$0.2	$0.6
Total	**$0.6**	**$0.9**	**$2.2**	**$3.7**

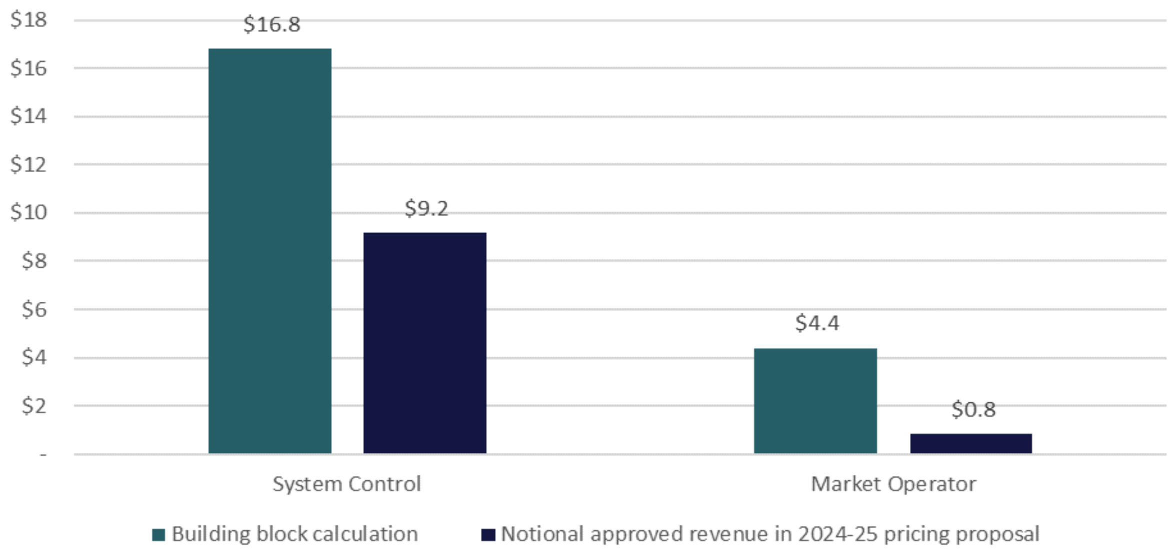
As discussed above, we sought to calculate a tax allowance based on the method in the AER regulatory framework. This has a value of zero. This is because our expected taxation costs including operating expenditure and depreciation have been calculated to be higher than our revenue for each regulatory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

9.2 True-up of 2024-25 revenue shortfall

We set regulated charges in 2024-25 by rolling forward the approved 2023-24 regulated price with an adjustment for inflation. The actual recovery amount is estimated to result in a revenue shortfall of $7.6 million for System Control and $3.6 million for Market Operator compared to the building block calculation as seen in **Figure 25**.

Consistent with the Commission's decision we propose to recover the shortfall between actual and allowed revenues occurring in 2024-25 by adding the amount to the RAB and depreciating the shortfall over seven years. This has the effect of increasing revenue in 2025-26 and 2026-27.

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



9.3 Maximum revenue

Table 17 sets out the proposed maximum revenue for the 2024-25 to 2026-27 regulatory period for System Control and Market Operator. The 2024-25 amount relates to the expected recovery of revenues based on the approved 2024-25 pricing proposal. The 2025-26 and 2026-27 years reflect the additional revenue above the building block calculation for the shortfall in 2024-25 revenue as per the method discussed in section 9.2. Consistent with the Commission's decision we have not sought to smooth revenue.

Table 17 – Proposed revenue allowance for System Control and Market Operator ($m, real 2023-24)

	2024-25	2025-26	2026-27	Total
System Control	$9.2	$18.4	$20.6	$48.1
Market Operator	$0.8	$5.2	$5.1	$11.1
Total	**$10.0**	**$23.6**	**$25.7**	**$59.3**

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 annual revenue arrangements, 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 Annual revenue arrangements

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 dollars per kilowatt hour ($/kWh) charge.

We have submitted our 2025-26 NTESMO pricing proposal in accordance with the proposed pricing mechanism in Attachment 11.2 and used the proposed revenue in this proposal. For 2026-27 (the final year of this regulatory period) we propose that NTESMO submit an annual revenue proposal to the Commission at least three months before 30 June 2026. **Attachment 11.2** sets out our proposed mechanism for setting annual prices for each regulatory year.

10.2 Indicative regulated charges

As noted in Chapter 2, the Commission approved the 2024-25 charges to account for inflation (based on the Australian Bureau of Statistics' June quarter 2023 consumer price index, weighted average of eight capital cities).

The indicative charges for 2025-26 year align with our draft pricing proposal that has been based on the proposed annual pricing escalation mechanism in Attachment 11.2. This includes an under-recovery amount for system control and market operator charges based on the closing account in 2023-24.

The indicative 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 DKPS only.

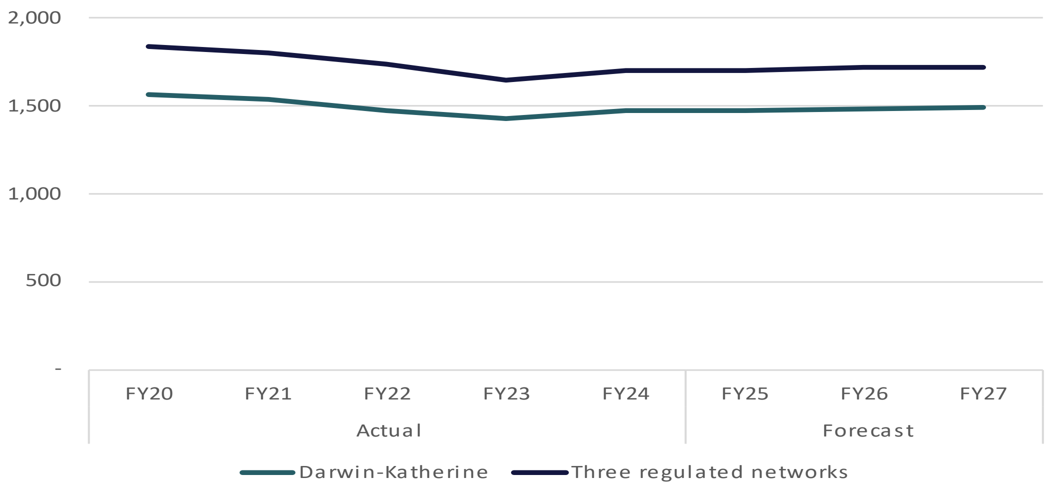
We have presented indicative regulated charges in nominal terms. We have escalated the revenue presented in real terms in Chapter 9, by applying inflation as presented in **Table 18** which is based on lagged actual inflation. For 2026-27 we have applied forecast inflation of 2.66% but this will be updated in the 2026-27 pricing proposal to reflect actual lagged inflation consistent with Attachment 11.2.

Table 18 – Inflation applied to calculate indicative tariffs

	2024-25	2025-26	2026-27
Forecast inflation	4.05%	2.42%	2.66%

Figure 26 shows that the energy consumption forecast for both DKPS 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 26 – 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 19**.

Table 19 – Indicative regulated charges for System Control and Market Operator ($/kWh, nominal)

$/kWh	2024-25	2025-26	2026-27
System Control	$0.005527	$0.011823	$0.013084
Market Operator	$0.000585	$0.003769	$0.003750

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 1.43% of the annual electricity bill of a typical small residential customer in the DKPS.[17] Despite the increase in proposed regulated charges in 2025-26, the combined impact is still very low and estimated at 3.49%.

Figure 27 shows the change in composition of System Control costs, assuming all other costs in the NT Power Systems stay constant in real terms.

Figure 27 – NTESMO's contribution to typical DKPS residential electricity bill comparison of 2024-25 to 2026-27(nominal $)

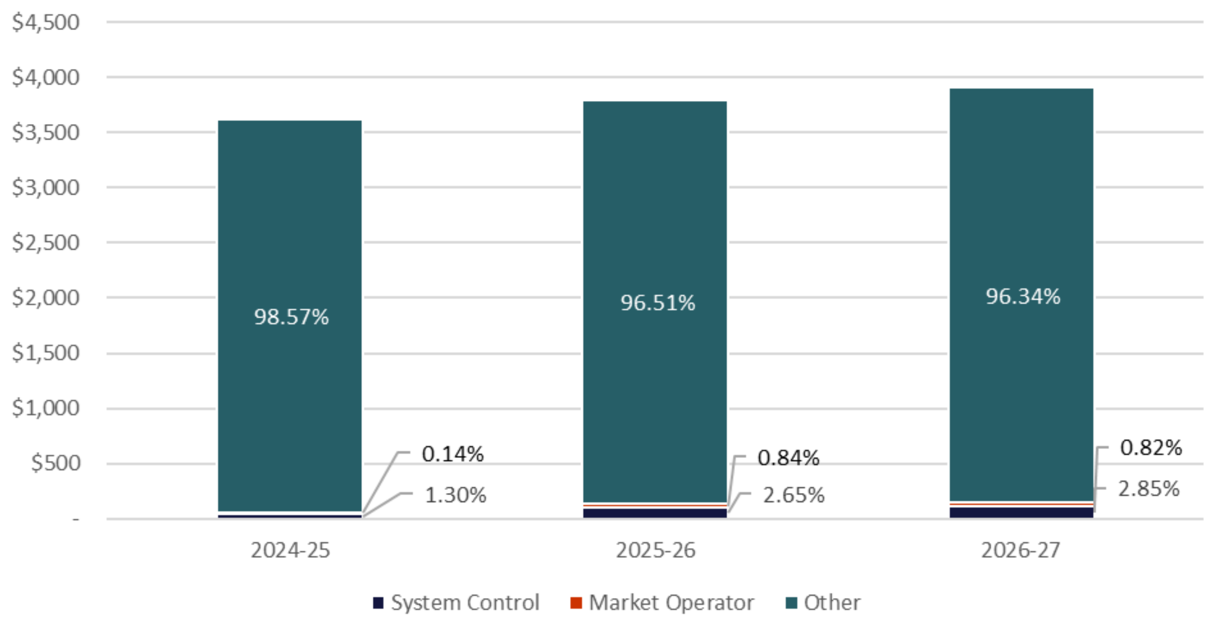


Table 20 shows the indicative change in electricity bill impacts between 2024-25 and 2025-26 for a retailer's customer in Alice Springs and Tennant Creek that have System Control regulated charges apply. The retailer's customers in these regulated regions do not receive a Market Operator charge. Customers under 750 MWh will continue to be protected by the NT Government's pricing order.

Table 20 – System Control regulated charge impacts for customers in Alice Springs and Tennant Creek ($, nominal)

$ Nominal	Volume (kWh)	2024-25 Charge	2025-26 Charge	Change ($)	% change
Small Residential	8,500	$46.98	$100.50	$53.52	113.9%
Large Residential	15,000	$82.91	$177.35	$94.45	113.9%
Small Medium Business	30,000	$165.81	$354.70	$188.89	113.9%
Medium Business	150,000	$829.05	$1,773.52	$944.47	113.9%
Large C&I	500,000	$2,763.50	$5,911.72	$3,148.22	113.9%
Industrial	1,000,000	$5,527.00	$11,823.45	$6,296.45	113.9%
Large Industrial	6,000,000	$33,162.00	$70,940.70	$37,778.70	113.9%

Table 21 shows the change in bill impacts for a retailer's customers in DKPS that have both System Control and Market Operator regulated charges apply. Customers who consume less than 750 MWh annually will continue to be protected by the NT Government's pricing order.

Table 21 – System Control and Market Operator regulated charge impacts for customers in Darwin-Katherine ($, nominal)

$ Nominal	Volume (kWh)	2024-25 Charge	2025-26 Charge	Change ($)	% change
Small Residential	8,500	$51.95	$132.53	$80.58	155.1%
Large Residential	15,000	$91.68	$233.88	$142.20	155.1%
Small Medium Business	30,000	$183.36	$467.77	$284.41	155.1%
Medium Business	150,000	$916.80	$2,338.84	$1,422.04	155.1%
Large C&I	500,000	$3,056.00	$7,796.13	$4,740.13	155.1%
Industrial	1,000,000	$6,112.00	$15,592.26	$9,480.26	155.1%
Large Industrial	6,000,000	$36,672.00	$93,553.53	$56,881.53	155.1%

11 Pass through mechanism

We have proposed pass through events consistent with the Commission's uncertainty mechanism decision and feedback received from the Commission regarding further clarification of the pass through event definitions and their application and proposed minor modifications.

Changes from our Initial Regulatory Proposal

Our Initial Regulatory Proposal included a framework for managing uncertainty within the regulatory period. We proposed pass through events based on the events prescribed in the NT NER and nominated events and a process where the prudency and efficiency of expenditure was mostly assessed on an ex-post basis.

In this Revised Regulatory Proposal, we have proposed the Commission's uncertainty mechanism in the decision paper and on recent feedback from the Commission, including the pass through events, materiality threshold, information requirements, process and timelines.

The purpose of this chapter is to identify the uncertainty mechanism to apply to the 2025-27 regulatory period. The Commission's decision paper prescribes a pass through mechanism for managing uncertain expenditures. There were several areas of the Commission's decision paper that were unclear to NTESMO which the Commission has clarified. We have adopted the Commission's pass through mechanism and have reflected the Commission's clarifications in this Revised Regulatory Proposal.

11.1 Application of uncertainty mechanism

Our proposal is to apply for an ex-ante uncertainty mechanism to allow NTESMO to claim operating and capital expenditure for a pass through event, subject to the prescribed criteria being met. This is consistent with the Commission's decision paper and clarifications provided by the Commission.

The pass through mechanism provides a way to adjust NTESMO's revenue within a regulatory period to recover the efficient costs of uncontrollable and material events that occur after the Commission's final decision on NTESMO's 2024-27 Revised Regulatory Proposal. It ensures consumers do not pay for uncertain but significant costs unless specified events occur.

While we propose to an ex-ante pass through mechanism consistent with the Commission's decision paper, there are two key areas where the Commission provided further clarification on the application of the mechanism including whether guidance notes will be applied in a similar way to the AER provides guidance notes.

The Commission has clarified that a pass through claim includes both capital and operational expenditure, which it will adopt consistently with the NT NER. Additionally, the Commission clarified that it does not intend to use guidance notes, however the AER's guidance notes may be a useful reference, noting also that on specific matters NTESMO can seek the Commission's advice in writing.

11.2 Pass through events

We propose that 8 passes through events apply in the 2025-27 regulatory period including retailer failure, regulatory change, service standards, tax change, insurance coverage, insurer's credit risk, natural disaster and terrorism. NTESMO has clarified with the Commission that:

- If the TEM reforms are implemented through a new or amended legal instrument (e.g. an Act or Regulation) that places requirements on NTESMO, the service standards event and regulatory event would likely apply.
- It is not considered necessary to alter the service standards event and regulatory event definitions to clarify that these definitions cover a situation where the TEM reforms do not vary, alter or change the nature and scope of the services provided by NTESMO. The Commission noted that it will adopt NT NER definitions.

Consistent with the Commission's clarifications and decision paper, **Attachment 11.1** includes our proposed definitions that are compliant with the Commission's requirements. Additionally, **Attachment 11.2** sets out our proposed calculation for pass through events.

11.3 Materiality threshold

Our proposal is to apply a 5% materiality threshold to uncertainty mechanism claims. For a pass through event to be eligible, the actual and forecast change in costs must be equal to or exceed 5% of the annual revenue requirement in the year in which the pass through event occurs.

We propose that the level of costs may include the cost impact of a single pass through event in a single year, or the total cost impact of an event over more than one year in the regulatory period to recognise the cumulative effect of the event in the regulatory period. We propose that a claim can also be made where more than one pass through event occurs in a regulatory year and the combined cost impact of those events in that year is equal to or exceeds the 5% threshold which recognises the compounding impact of multiple events.

While our proposal is consistent with the Commission's decision paper, we have clarified with the Commission that:

- It intends for the calculation of costs to include forecast operating and capital expenditure. This is the same as the AER's approach under the NT NER.
- Where a pass through event includes shared costs across Power and Water's ringfenced businesses, NTESMO's cost portion should be the portion allocated to NTESMO under the AER's approved cost allocation method.

11.4 Information to be provided to the Commission

We propose that when seeking approval for an eligible pass through event, NTESMO will provide, by written notice, the following information:

- The details of the pass through event include the date on which the event occurred.
- The increase in costs that have been incurred and are likely to be incurred in each regulatory year during the current regulatory period (and future regulatory periods where relevant) and the amount NTESMO proposes should be passed through to customers.
- Evidence of the actual and likely increase in costs and that these costs occur solely as a consequence of the event.
- Information on NTESMO's decisions and actions in relation to mitigating the risk of and reducing the magnitude of costs associated with the pass through event.
- This is consistent with the Commission's decision paper.

11.5 Process timeframes for eligible events

NTESMO clarified with the Commission that its decision paper intended for NTESMO to notify the Commission of a pass through within 20 business days of it becoming aware of a pass through event and the Commission has clarified the process for multiple pass through event claims occurring in a regulatory year. These positions are reflected in the proposed process.

We propose the following steps and timeframes will apply in relation to notifications and approvals of pass through events and associated claims:

- Within 20 business days of NTESMO becoming aware of the occurrence of a pass through event that meets or exceeds the materiality threshold, or where multiple pass through events occur in a regulatory year and the accumulative cost meets or exceeds the materiality threshold.
- NTESMO will provide a claim to the Commission if NTESMO considers the materiality threshold has been reached. The timing of the claim will be either:
  - If the claim relates to a single pass through event in a single year, then within 90 business days of NTESMO becoming aware of the occurrence of a pass through event, NTESMO is to provide the Commission with a claim that meets the information requirements (see section above) for approval.
  - If the claim relates to more than one pass through event occurring in a regulatory year and the combined cost impact of those events in that year exceeds the materiality threshold, then within 90 business days of the end of that regulatory year, NTESMO is to provide the Commission with a claim that meets the information requirements (see section above) for approval.
- Within 60 business days after receipt of a claim that meets the Commission's requirements, the Commission will approve or not approve the amount and the year (or years) in the regulatory period in which that amount is to be passed through to customers. Where a claim is not approved, the Commission will provide the reasoning for its decision.
- The Commission may request additional information by written notice in relation to a claim.
- During that 60-business day period, the Commission may extend the time for its assessment of NTESMO's claim by a further 60 business days by written notice to NTESMO if the Commission considers the complexity or difficulty of assessing or quantifying the effect of the pass through event justifies the extension.
- Within 5 business days of notifying NTESMO of its decision to approve or not approve the claim, the Commission will publish its decision on the Commission's website.

Attachment list

Attachment No	Attachment Title
2.1	Australian Energy Regulator Approved Cost Allocation Methodology
2.2	Core Operations Cost Allocation Methodology
2.3	Investment Delivery Framework Management Standard and Project Investment Delivery Management Standard
5.1	Activity Allocation and Obligation Mapping
5.2	Operational Expenditure Forecast
6.1(a)	TDE Business Case
6.1(b)	NTESMO Dispatch Systems Roadmap Regulatory Business Case
6.1(c)	Summary of key budget variance between TDE Business Case and Regulatory Business Case
6.2	Corporate capex allocation model
7.1	Transitional Tools Compliance Summary
7.2	Settlements System Compliance Summary
7.3	Retrospective Costs for the Investment of the Territory Dispatch System
10.1	Energy Consumption Forecast
11.1	Pass Through Mechanism
11.2	Annual Pricing Escalation Mechanism
12	Economic models

Abbreviations

Abbreviation	Description
AER	Australian Energy Regulator
Capex	Capital expenditure
CAM	Cost allocation methodology
Commission	Utilities Commission of the Northern Territory
COTS	Commercial of the shelf
CPI	Consumer price index
DER	Distributed energy resources
DKPS	Darwin-Katherine power system
DKDF	DKPS demand forecast
EPMC	Enterprise Portfolio Management Committee
ER Act	Electricity Reform Act 2000
ESS	Essential system services
FCT	The Forecast Compliance Tool (FCT)
GPS	Generator performance standards
ICT	Information Communication and Technology
I-NTEM	Interim NT energy market
kW	Kilowatt
kWh	Kilowatt hour
kVA	Kilovolt ampere
LV	Low voltage
MSATS	Market Settlement and Transfer Solution
MW	Megawatt
MWh	Megawatt hours
NEM	National electricity market

Abbreviation	Description
NER	National Electricity Rules (or Rules*)*
NMI	National metering identifier
NPV	Net present value
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
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
WACC	Weighted average cost of capital

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