Northern Territory Electricity Outlook Report Update 2024

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Disclaimer

The 2023 Northern Territory Electricity Outlook Report (NTEOR) and 2024 NTEOR Update (this report) are prepared using information sourced from participants of the electricity supply industry, Northern Territory Government agencies, consultant reports and publicly available information. The 2023 NTEOR is based on information from the financial year ending 30 June 2023 and a forecast calculated for a 10-year outlook period from 1 July 2023 to 30 June 2033 (outlook period). The 2024 NTEOR Update is based on the 2023 NTEOR and revised information received in late-2024. The Utilities Commission understands the revised information received for the 2024 NTEOR Update to be current at 14 March 2025.

The 2023 NTEOR and 2024 NTEOR Update contain analysis and statements based on the Commission and Australian Energy Market Operator's interpretation of data provided by Territory electricity industry participants. The Commission has sought to align its reporting of data with the other Australian jurisdictions where possible to enable comparison. However, there are some differences, therefore any comparisons should only be considered indicative.

Any person using the information in the 2023 NTEOR or 2024 NTEOR Update should independently verify the accuracy, completeness, reliability and suitability of the information and source data. The Commission accepts no liability (including liability to any person by reason of negligence) for any use of the information in the 2023 NTEOR or 2024 NTEOR Update for any loss, damage, cost or expense incurred or arising by reason of any error, negligent act, omission or misrepresentation in the information in this report or otherwise.

Any questions regarding this report should be directed to the Utilities Commission utilities.commission@nt.gov.au or by phone 08 8999 5480.

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About this report

Since 2018, the Utilities Commission of the Northern Territory (Commission) has published an annual Northern Territory Electricity Outlook Report (NTEOR), which provides an assessment of the generation capacity of the three largest power systems in the Territory (Darwin-Katherine, Alice Springs and Tennant Creek), to meet projected electricity demand over a 10-year outlook period.

The main purpose of the NTEOR has been to inform decisions by government, licensees and investors by providing forecasts of prospective trends in system demand and supply reliability to identify challenges, gaps and opportunities. The NTEOR has been produced in accordance with section 45 of the *Electricity Reform Act 2000*.

Unlike previous editions of the NTEOR, which were prepared following detailed modelling by the Australian Energy Market Operator (AEMO), this 2024 NTEOR Update is a high-level, qualitative generation adequacy assessment, examining whether there have been material changes in the Territory's power systems since the 2023 NTEOR. It identifies broad trends in generation adequacy and provides a general indication of whether the risk to customer supply has remained the same, improved or worsened in the short (0 to 3 years), medium (4 to 6 years) and long term (7 to 9 years) due to any known material changes.

This assessment does not rely on a formal risk methodology or matrix but instead reflects the Commission's broad consideration of generation adequacy. The Commission has adopted a three-tier risk rating of low, medium and high to provide a coarse indication of potential reliability concerns. The Commission defined the risk ratings as:

- low risk – indicates no identified issues and a substantial buffer between demand and supply
- medium risk – reflects the presence of some challenges and a reduced but still sufficient buffer, requiring caution and vigilance
- high risk – signals significant concerns, a minimal or non-existent supply buffer, and a strong likelihood of supply shortfalls during periods of high demand, warranting immediate action.

This risk classification is intended to provide a broad, directional view of generation adequacy in the Territory's three largest power systems rather than a precise probabilistic forecast.

The decision to shift to a qualitative assessment for the Commission's 2024 outlook and not undertake modelling or a full adequacy assessment reflects recent work undertaken by the Northern Territory Electricity System and Market Operator (NTESMO), under the direction of the Territory Government, to inform a Regulated Electricity System Investment Plan (RESIP).

Work undertaken by NTESMO to deliver a RESIP for government's consideration includes detailed demand and supply forecasts, generation adequacy insights and system planning analysis, covering the same scope as the previous NTEOR modelling while also incorporating a greater level of detail and additional considerations. Given this overlap, the Commission decided that producing an NTEOR with the same level of modelling as previous years would result in duplication of effort and potential inefficiencies.

Further, electricity system modelling is highly dependent on input assumptions and methodologies, with some inputs being particularly sensitive to small variations. If the Commission had proceeded with its own modelling alongside the RESIP, it could have led to two publicly available sets of modelling results that may not have fully aligned. While both would have been valid within their respective assumptions, such discrepancies could have created unnecessary confusion for stakeholders.

By focusing this update on qualitative assessments and key changes since the 2023 NTEOR, the Commission aims to provide a broad, high-level assessment of system adequacy while ideally more detailed and actionable planning is progressed through the RESIP or other planning process as decided by government.

As the NTEOR Update only provides a high-level, qualitative updated assessment of generation adequacy based on new information from licensees, and other stakeholders and sources, the findings should be read in conjunction with the 2023 NTEOR, which contains detailed methodology and assumption information, and modelling results.

The following limitations of the 2024 NTEOR Update should be noted:

1. Capacity versus reliability and security – although relevant discussion is included, this update is only an assessment of installed capacity relative to demand. It does not assess whether the capacity is reliable, secure or flexible enough to meet operational requirements. Generator availability and performance issues are addressed in the Commission's Northern Territory Power System Performance Review.

2. Exclusion of large-scale solar in the supply analysis – while new large-scale solar projects have connected to the Darwin-Katherine power system, they have not been included in the supply-side assessment of the update. This is due to the high-level qualitative nature of the 2024 NTEOR Update, which assesses changes in dispatchable (thermal) generation capacity against previously forecast maximum demand. As maximum demand is typically forecast to occur in the late afternoon or early evening, when solar output is minimal or zero, large-scale solar is not expected to materially contribute to meeting demand during these critical periods.

   Further, due to system constraints and technical issues, some large-scale solar projects are still subject to operational limitations imposed by System Control and not yet operating at full capacity.

   The Commission acknowledges that large-scale solar generation is expected to play an important role in the Territory's future energy mix, particularly in improving affordability and reducing emissions. However, in the context of this update's specific focus on periods of maximum demand, large-scale solar was not considered relevant for assessing system adequacy or reliability risk.

3. Reliance on licensee information – this update is heavily dependent on data and information provided by licensees, including generation retirement schedules, maintenance rates and capacity availability. The Commission has not independently verified this information (although has applied a reasonableness test) and acknowledges that operational conditions may change over time.

In particular, the Commission notes significant uncertainty surrounding the life extension works for key generators at Channel Island power station (CIPS). Territory Generation has not provided detailed or formal information on timing of the works, their duration or generator operational limitations following the works. As a result, while the updated retirement dates have been factored into the Commission's assessment, the practical impact of these life extensions on system reliability is unclear.

Key findings and recommendations

The 2024 NTEOR Update provides a high-level, qualitative assessment of electricity supply and demand in the Territory's three largest power systems, Darwin-Katherine, Alice Springs and Tennant Creek, over an outlook period to 2032-33, based on previous modelling undertaken for the 2023 NTEOR and material changes since. The assessment found that while there have been some potentially positive developments since the 2023 NTEOR, the fundamental challenges of generation reliability and adequacy, and the transition to more renewable energy, remain.

It is important to note the Commission's assessment in this update is subject to the limitations outlined in the "About this report" section, including its focus on installed capacity relative to demand rather than the reliability and security of that capacity, the exclusion of large-scale solar generation in the supply-side assessment and the reliance on information provided by licensees.

System reliability outlook

The assessment of generation adequacy in the 2024 NTEOR Update indicates some changes in reliability risks across the three power systems:

Darwin-Katherine

- A new record minimum demand in 2023-24 highlights the growing operational challenges associated with rising behind-the-meter solar photovoltaic (PV) systems, which Power and Water Corporation (PWC) System Control continues to manage through proactive interventions.
- Territory Generation's planned life extension works at Channel Island power station may improve reliability in the medium term but the lack of information about generator availability during and after the works creates significant uncertainty.
- The Commission considers the risk of not meeting customer demand may have increased in the short term due to the life extension works however remains at medium. Despite potential improvements, the risk remains high in the medium to long term. Long-term reliability and security continue to rely on timely investment in new generation and supporting technologies.

Alice Springs

- While the short-term deferral of the Ron Goodin power station (RGPS) retirement slightly improves generation adequacy, the retirement of two units and ongoing forced outages at the station mean the impact is limited. The power system remains at medium risk of not meeting customer demand in the short, medium and long term, with continued vulnerability due to a tight margin between demand and supply.
- Recent information suggests a large industrial load previously expected to mitigate minimum demand challenges may not contribute as forecast, with potential constraints limiting its availability. As a result, minimum demand issues are an immediate and ongoing concern.
- Without further investment or improved utilisation of existing generation assets, Alice Springs is expected to remain exposed to reliability challenges throughout the outlook period.

Tennant Creek

- The Tennant Creek power system remains at low risk of not meeting customer demand in the short and medium term, supported by an ongoing capacity buffer. However, the long-term outlook has deteriorated slightly with the planned retirement of five units between 2028 and 2031, alongside reduced output from units 19 to 21. As a result, the Commission has cautiously raised the long-term risk assessment from low to medium.

Overall, the major reliability concerns from the 2023 NTEOR remain, particularly in the Darwin-Katherine power system, where a potential medium-term improvement from planned life extension works cannot be confirmed due to significant uncertainty regarding their timing, impact and effectiveness. The fundamental supply shortfall issue has not been resolved.

Broader industry and policy considerations

The Commission's assessment of electricity demand and supply highlights several key priorities for government and industry that must be addressed to ensure a secure, reliable and cost-effective power system. These considerations align with findings from previous NTEORs and remain critical in the future interests of the Territory's electricity supply industry, electricity consumers and taxpayers:

- **significant investment is unavoidable** – substantial investment in capacity and essential system services is required to address current and looming power system reliability, security and affordability issues
- **a Regulated Electricity System Investment Plan is needed** – responsibility for whole-of-system planning needs to be clear. Investment decisions should avoid short-term fixes where possible and instead focus on planning and delivering the most appropriate solutions from a cost-benefit perspective for the whole system
- **competition is critical** – while Territory Generation is seeking to address short to medium-term issues through life extensions and delayed retirements, new investment should follow a competitive procurement process to foster innovation and drive down costs
- **non-generation solutions must play a greater role** – reducing the need for new generation through demand management, pricing signals, energy efficiency and better utilisation of existing assets can limit costs.

An opportunity for the Territory Government and industry

As discussed in the 2023 NTEOR and previous reports, and notwithstanding recent decisions to undertake some life extension works and or defer some generation retirements, urgent and appropriate investment in capacity and essential system services to address current and looming power system issues are needed. These investment decisions cannot be supported in an efficient way under the current arrangements, and electricity market reforms are needed.

Potential electricity market reform has been an ongoing consideration by Territory governments for over 10 years. Previous governments have announced reforms but limited progress has been made in their implementation.

The Territory's electricity supply industry has reached a critical juncture. Despite planned works to extend the life of some generators, the underlying challenges have not disappeared. Without clear direction and decisive action, the Territory risks finding itself in the same position year after year, reacting to crises rather than providing a clear and accountable framework for a secure and sustainable energy future.

The Commission urges the new Territory Government, industry and stakeholders to seize this opportunity for meaningful reform and ensure the Territory's power system is positioned to support economic growth, attract investment, and deliver reliable, secure and sustainable electricity at least cost for all Territorians.

1 | Darwin-Katherine

Table 1 provides an overview of the Commission's assessment of the risk (or likelihood) of not meeting customer demand in the Darwin-Katherine power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those that have a material impact on the assessed risk.

Table 1: Risk of not meeting customer demand in the Darwin-Katherine power system

Risk of not meeting customer demand		
Short term	Medium term	Long term
Medium	High	High
Change since the 2023 NTEOR		
0 – 3 years	4 – 6 years	7 – 9 years
There is a high degree of uncertainty on the impact the life extension works at CIPS will make given the lack of available information. The risk remains at medium.	Territory Generation's plan to undertake life extension works to delay the retirement of four large generators at CIPS may reduce the risk of not meeting customer demand in the medium term, but the risk remains at high.	Territory Generation's life extension works and associated delayed retirement of four large generators at the CIPS is not a long-term solution and assessment of risk in the long term remains high.

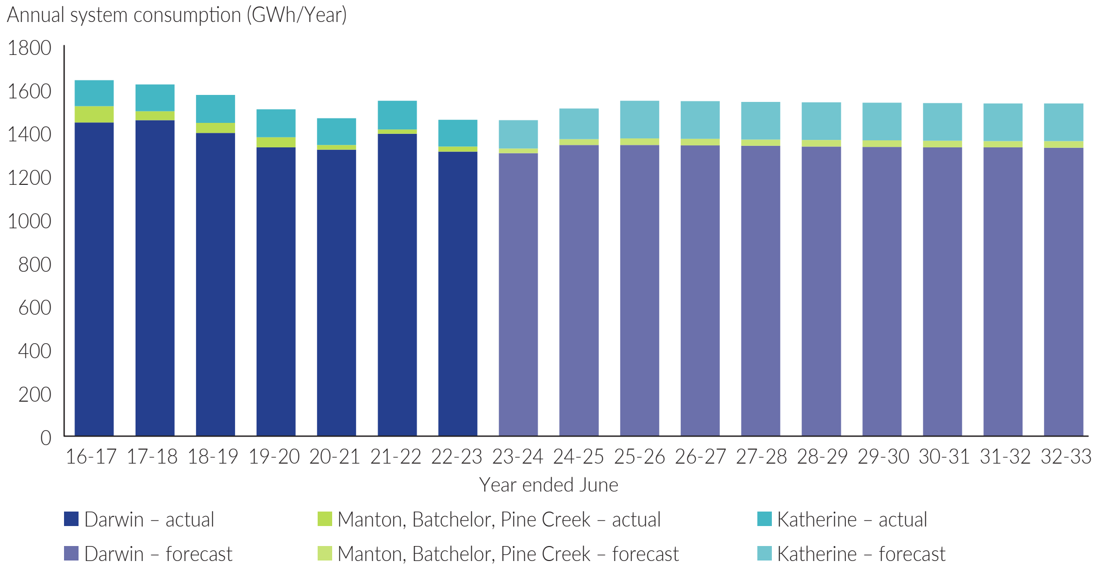
Demand

Summary of 2023 NTEOR findings

Annual electricity consumption

The 2023 NTEOR forecasted consumption in the Darwin-Katherine power system over the 10-year outlook period to remain relatively stable as increasing penetration of behind-the-meter solar PV offset expected growth from population increases, electric vehicles (EVs) and battery storage adoption, as shown in Figure 1.

Figure 1: Historical and forecast annual system consumption for Darwin-Katherine as reported in the 2023 NTEOR, 2016-17 to 2032-33[1]



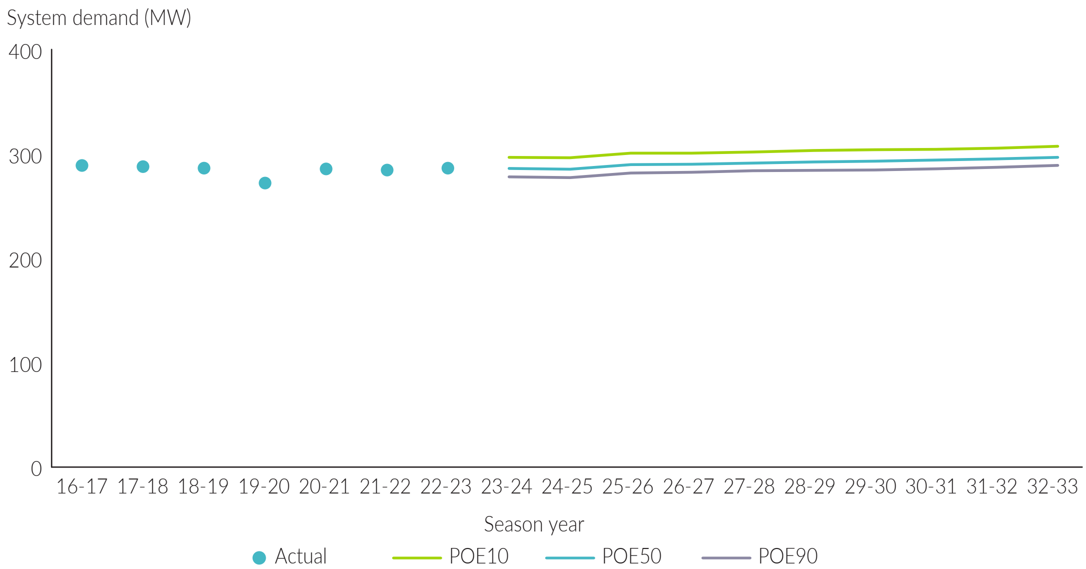
1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 is forecast data as actuals were not available at the time of publication of the 2023 NTEOR.

Maximum demand

Historically, airconditioning loads during the wet season have been the primary driver of maximum system demand in the Darwin-Katherine power system.

The 2023 NTEOR forecasted a slight increase in peak demand over the outlook period, as shown in Figure 2, driven by new industrial developments (block loads). The time of peak demand was projected to shift later into the evening due to the continued uptake of rooftop solar PV. By the end of the outlook period, peak demand was expected to occur after sunset, presenting new operational challenges.

Figure 2: Historical and forecast maximum system demand in the Darwin-Katherine by season year (year ending 31 August) 2016-17 to 2032-33 as reported in the 2023 NTEOR[1]



1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

Minimum demand

The 2023 NTEOR forecasted minimum demand in the Darwin-Katherine power system to continue its downward trajectory, largely due to increasing rooftop solar PV installations, as shown in Figure 3. The trend of minimum demand shifting from early morning to midday was identified as a significant system security risk. It was discussed that this shift could be mitigated by mechanisms such as load shifting, battery storage and industrial demand management.

Figure 3: Historical and forecast minimum system demand in Darwin-Katherine by season year (year ending 31 August), 2016-17 to 2032-33 as reported in the 2023 NTEOR[1]

1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

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Maximum demand

In 2023-24, the Darwin-Katherine power system recorded a maximum demand of 282.1 Megawatts (MW) in December 2023, which was slightly lower than the 286.68 MW recorded in 2022-23.[1] The recorded maximum demand was within the range forecast in the 2023 NTEOR, which projected maximum demand for 2023-24 to be 296.93 MW (probability of exceedance (POE[2]) 10), 286.29 MW (POE50), and 278.18 MW (POE90).

Minimum demand

The Darwin-Katherine power system reached a new record minimum demand of 64.5 MW on 8 June 2024, lower than the 65.68 MW recorded in 2022-23. This minimum demand was slightly above the POE90 forecast (60 MW) in the 2023 NTEOR but below the POE50 (70.41 MW) and POE10 (80.74 MW) forecasts.

1 Actuals reported in the 2023 NTEOR (for 2022-23) and 2024 NTEOR Update (for 2023-24) are not directly comparable due to differences in data sources, methodologies and measurement points.

2 A 50% probability of exceedance (POE50) forecast is expected statistically to be met or exceeded one year in two, based on average weather conditions. A 10% POE (POE10) forecast for maximum demand or 90% POE (POE90) forecast for minimum demand is based on more extreme conditions than could be expected one year in 10. A 90% POE (POE90) forecast for maximum demand or 10% POE (POE10) forecast for minimum demand is based on less extreme conditions than could be expected nine years in 10. By definition the observed demand outcomes will occasionally fall outside the forecast 10% to 90% POE range. In one of 10 years, the outcome is likely to be under, and in another one of 10, it is likely to be above the range.

The Commission understands that minimum demand could have fallen even lower during 2023-24 had PWC System Control not taken proactive measures to maintain system security. Among other strategies, PWC directed large behind-the-meter solar systems to turn off and instead draw electricity from the network, increasing system demand and preventing minimum demand from reaching levels that System Control considers unknown and risky for maintaining power system security. This continues to highlight the growing challenges associated with high levels of uncontrollable behind-the-meter rooftop solar PV generation during daylight hours.

Electric vehicles, behind-the-meter solar and batteries

Three key demand drivers, specifically, electric vehicle (EV) uptake, behind-the-meter solar and batteries, have not materially changed since modelling was undertaken for the 2023 NTEOR.

In terms of EV uptake, AEMO's approach in the 2023 NTEOR leveraged national trends to forecast EV uptake in the Territory. The Commission is not aware of any changes that would materially impact the previous projections.

For behind-the-meter solar and batteries, there have been some changes since the 2023 NTEOR modelling, including the following new solar and battery incentives:

- solar for multi-dwellings grant scheme – provides up to $7,500 per dwelling for shared rooftop solar installations in multi-unit developments
- Home and Business Battery Scheme – offers up to $12,000 per system for the purchase and installation of new solar PV with an eligible battery and inverter, or an eligible battery and inverter to complement an existing solar PV system
- Jacana Energy's increased feed-in tariff – from 1 July 2025, Jacana Energy's feed-in-tariff will increase to 18.66c/kWh during peak hours (3pm to 9pm).[3]

However, as with EV uptake, the Commission considers it unlikely the changes would materially impact the previous projections or any new projections at this stage. This is on the basis the 2023 NTEOR assumptions accounted for previous schemes, or a version of the schemes (in relation to the Home and Business Battery Scheme), and any material or consistent impacts from changes to the feed-in tariff will take some time to be observed and quantified.

Notably, increased battery adoption may encourage load shifting, with stored solar energy being discharged into the network during evening peak periods. While this could help increase midday minimum demand and reduce peak loads, the short-term impact remains uncertain.

Economic and climate drivers

The 2023 NTEOR accounted for economic and weather-related demand drivers in its modelling. The Commission has not identified any significant changes in economic activity or climate trends that would materially alter these assumptions.

Block loads

Block loads are the most notable demand-side change since the 2023 NTEOR. The Commission requested updated block load information from the PWC. The new information reflects minor timing and load size adjustments and includes new committed projects.

3 The feed-in-tariff increase is expected to be implemented through a new electricity pricing order made by the Treasurer under section 44 of the ***Electricity Reform Act 2000*** prior to 1 July 2025.

Figure 4 and Table 2 illustrate the changes in block load assumptions for the Darwin-Katherine power system between the 2023 NTEOR and 2024 NTEOR Update, based on updated information from PWC.

Figure 4 shows the quarterly change (increase or decrease in MW) over time, allowing for a visual representation of the magnitude and timing of changes. The chart does not display total block load demand or system demand, only the variation in block load assumptions.

Table 2 summarises the average change in block load assumptions on a financial-year basis. The values represent the average of the four quarters within each financial year.

While both the chart and table reflect the same underlying changes, they are not directly comparable due to differences in the level of granularity (quarterly vs. annual averages). These figures provide an indicative, high-level view of the adjustments rather than a precise measure.

Figure 4: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2024 NTEOR Update, from 2024-25 to 2032-33

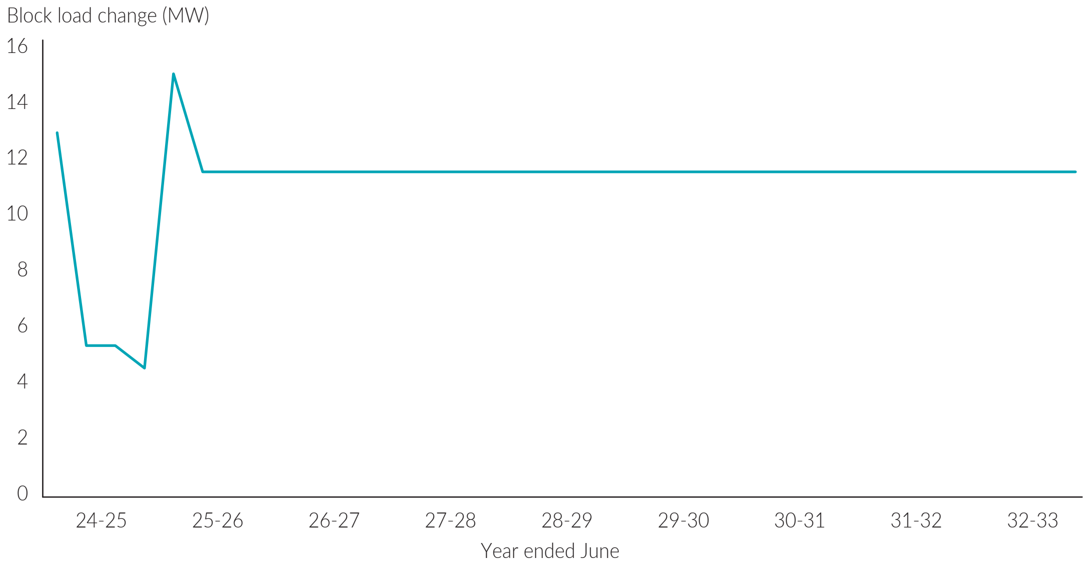


Table 2: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2024 NTEOR Update on a financial year basis, from 2024-25 to 2032-33

	Change (MW)
2024-25	7.1
2025-26	12.5
2026-27	11.6
2027-28	11.6
2028-29	11.6
2029-30	11.6
2030-31	11.6
2031-32	11.6
2032-33	11.6

As shown above, expected block load growth has increased compared to 2023 NTEOR projections, particularly from 2025-26 onward, with a peak increase of about 15 MW (quarter 1 of 2025-26). However, these projections represent a worst-case scenario, assuming maximum loads operate at full capacity simultaneously. In reality, loads fluctuate, making actual demand likely lower than the theoretical maximum. Compared to a POE50 maximum demand forecast from the 2023 NTEOR (289.8 MW in 2025-26), the additional block load is relatively small.

Given the minor scale of block load increases relative to system-wide maximum demand, the Commission does not expect these changes to materially impact the overall demand forecast.

Demand conclusion

Based on its assessment of updated information, as discussed above, the Commission finds no material change in demand drivers for the Darwin-Katherine power system since the 2023 NTEOR. As a result, any changes in the supply-side assessment do not need to factor in new demand considerations.

However, the Commission notes a new record minimum demand was recorded in 2023-24. The continuing impact of uncontrollable behind-the-meter solar PV generation has been managed by PWC System Control to date through taking proactive steps in the background to maintain system security, including directing large behind-the-meter solar PV systems to temporarily switch off and draw electricity from the network when required. This underscores the growing challenges ahead.

Supply

Summary of 2023 NTEOR findings

The Darwin-Katherine power system was forecast to face increasing generation adequacy risks over the 10-year outlook period, driven primarily by aging gas generation retirements at the CIPS.

In terms of existing and committed generation, the system remains heavily dependent on gas-fired generation, with large-scale solar playing a growing role. Six large-scale solar farms were considered committed in the 2023 NTEOR, along with the CIPS battery energy storage system and unit 10. Transmission constraints on the 132 kilovolt network to Katherine were identified as a factor limiting reserve capacity in certain areas.

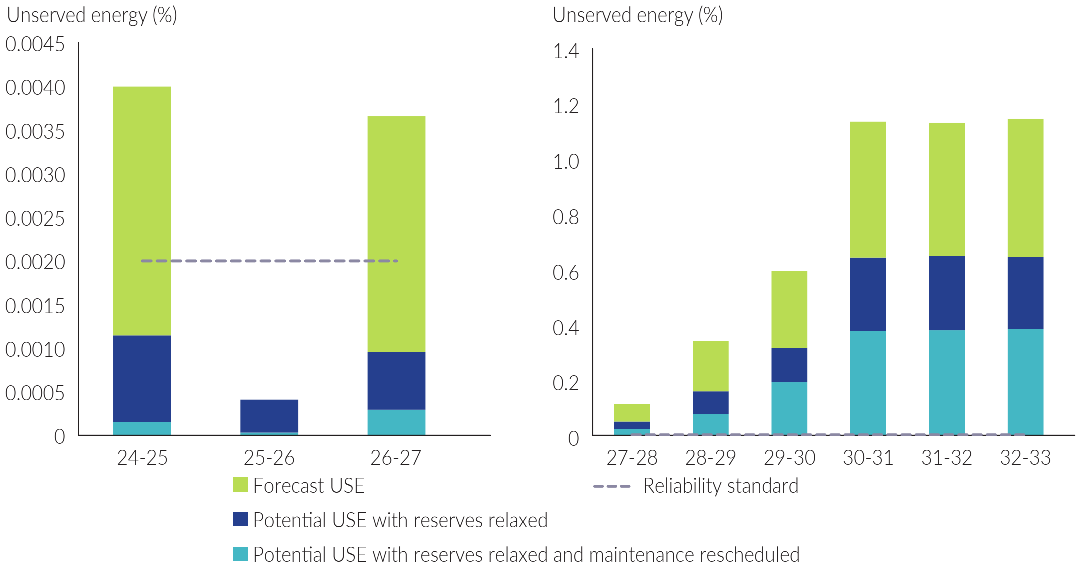
The 2023 NTEOR highlighted two distinct phases of supply-side risk:

1. **Short term (2024-25 and 2026-27), manageable reliability risks** – the modelling identified some risks to customer reliability in 2024-25 and 2026-27, largely due to scheduled generator maintenance affecting available capacity. However, these risks were assessed as manageable, as they could likely be mitigated by optimising maintenance schedules to ensure sufficient reserve capacity during peak periods. The Commission considered these risks were unlikely to materialise, provided maintenance was strategically planned.

2. **Medium to long term, significant and persistent reliability challenges** – from 2027-28, the system's reliability outlook deteriorated sharply, as expected major generation retirements at CIPS created a structural shortfall in supply. The expected retirement of approximately 185 MW of gas generation capacity, representing 35% of the system's summer capacity, was projected to lead to sustained capacity shortfalls for the remainder of the outlook period. Unlike earlier risks, these could not be addressed through operational measures (such as maintenance optimisation), making new generation investment critical to maintaining system reliability.

The supply-side risks to customer reliability are reported in the form of forecast unserved energy and shown in Figure 5, as reported in the 2023 NTEOR.

Figure 5: Forecast reliability, Darwin-Katherine system, 2024-25 to 2032-33, as reported in 2023 NTEOR



The Commission emphasised the urgency of addressing these risks through committed investment in and delivery of new capacity.

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Generation capacity

Since the 2023 NTEOR, Territory Generation has advised of life extension works to delay the planned retirements of key generators at CIPS (except for unit 1, which is now expected to retire a year earlier than assumed in the 2023 NTEOR). These delays have the potential to temporarily improve the system's capacity outlook to some degree, particularly in the medium term, but there are some unknowns that are discussed below.

These delayed retirements at the CIPS are shown in Table 3.

Table 3: Delayed retirements at the Channel Island power station

Generator unit	2023 NTEOR retirement date	2024 NTEOR Update retirement date	Change
Unit 1	31/12/2026	01/01/2026	1 year earlier
Unit 2	31/12/2026	31/12/2030	4-year extension
Unit 4	31/12/2027	31/12/2034	7-year extension
Unit 5	31/12/2027	31/12/2034	7-year extension
Unit 7	31/12/2029	31/12/2035	6-year extension

To date the Commission's NTEOR modelling and assessments have relied on generators' reported summer and winter generator unit capacities. The 2024 NTEOR Update has largely followed the same approach. However, in its most recent update in March 2025, Territory Generation provided additional unit capacity information using a 'sustainable capacity' measure. Where the Commission found a material difference between the summer/winter capacities and the reported sustainable capacity, the Commission has incorporated the updated (sustainable) capacity into its assessment.

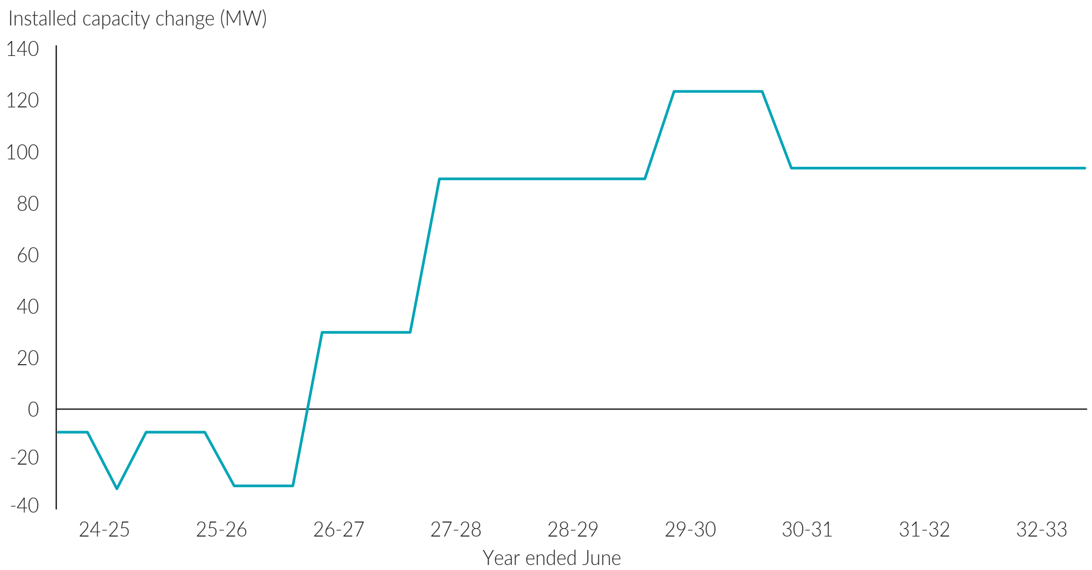
In addition to reporting where there are material differences in capacities (such as for unit 1 at CIPS, which had a summer capacity of 30.02 MW and a winter capacity of 31.6 MW reported by Territory Generation for the 2023 NTEOR but a sustainable capacity of 21 MW reported for this 2024 update), the Commission is aware there are generation units with constraints or restrictions applied that limit practical availability. Where this is the case, the particular unit's effectiveness as a dispatchable resource to meet system demand is reduced.

Figure 6 illustrates the changes in installed summer[4] capacity of thermal generation between the 2023 NTEOR and 2024 NTEOR Update, based on updated information from licensees.

Figure 6 shows the increase or decrease in installed summer capacity (MW) over time. The chart does not display total generation capacity, only the variation in assumptions between the two reports. The x-axis represents time, with data points for each quarter in each financial year, while the y-axis represents the change in installed summer capacity of thermal generation (MW) rather than absolute capacity values.

This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

Figure 6: Change in total MW of thermal generation capacity (summer[1]) assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update, from 2024-25 to 2032-33



1 Except for CIPS unit 1, which uses 'sustainable capacity' as reported by Territory Generation.

4 Except for CIPS unit 1, which uses 'sustainable capacity' as reported by Territory Generation.

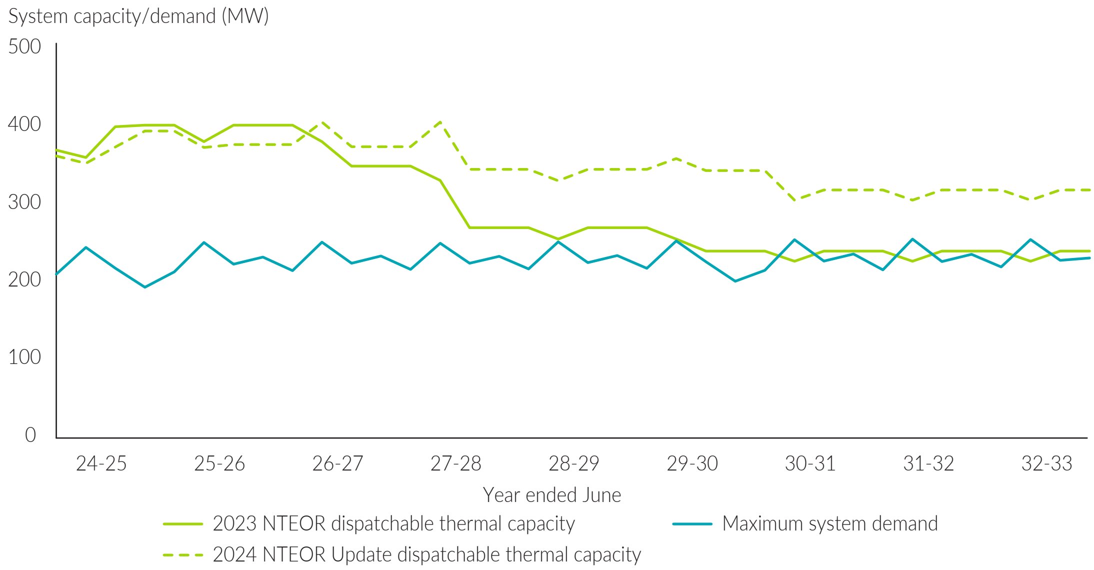
At face value, the planned life extension works for four large generators at CIPS and delay of their retirement would appear to improve the reliability outlook for the Darwin-Katherine power system in the short to medium term (2024 to 2030). However, Territory Generation has not provided any detailed or formal information to the Commission regarding the life extension works, including their timing and duration, or generator operational limitations following the works. The Commission understands the generators will undergo maintenance and or upgrades, but key details such as when this work will occur and how long the units will be unavailable for has not been advised. Depending on the scheduling of these works, the availability of generation capacity to meet customer demand could be impacted in the short to medium term.

Additionally following life extension works, the Commission understands the generators may have reduced annual operating hours. The Commission does not know the extent of this limitation, or the timing and conditions under which these generators will be available for dispatch (or the impact on other generators that will be relied upon more frequently). As a result, the true impacts (positive and negative) of the life extension works on generation adequacy in the Darwin-Katherine power system are uncertain.

Given these uncertainties, the Commission reiterates that while life extension works may provide some relief in the medium term, they may create additional challenges in the short term, and do not eliminate the need for new investment in generation capacity and supporting technologies. The risk in the long term remains high. A long-term sustainable solution remains critical to ensuring system reliability.

To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 7). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments only account for summer[5] dispatchable capacity (not seasonal as per the original chart). Noting the discussion above, while this coarse visual assessment does not account for generation availability changes, it offers a useful high-level comparison.

Figure 7: Forecast dispatchable thermal capacity and maximum demand, Darwin-Katherine power system, 2024-25 to 2032-33



1 Except for CIPS unit 1, which uses 'sustainable capacity' as reported by Territory Generation.

5 Except for CIPS unit 1, which uses 'sustainable capacity' as reported by Territory Generation.

Exclusion of large-scale solar from the supply-side assessment

As outlined in the *About this report* section, large-scale solar generation has not been included in this update's supply-side assessment. This approach applies to all three regulated power systems assessed, Darwin-Katherine, Alice Springs and Tennant Creek.

The 2024 NTEOR Update uses a high-level qualitative approach, which focuses on changes in dispatchable (thermal) generation capacity relative to previously forecast maximum demand. Maximum demand is typically forecast to occur in the late afternoon or early evening, when solar output is minimal or zero. As a result, large-scale solar is not expected to materially contribute to meeting demand during these critical periods and has therefore not been factored into the reliability risk assessment.

In addition, due to system constraints and technical issues, several new large-scale solar projects in the Darwin-Katherine power system remain subject to operational limitations imposed by System Control. These limitations have prevented some projects from operating at full capacity since connecting to the network.

The Commission recognises that large-scale solar will play an important role in the Territory's future energy mix, particularly in reducing long-term costs and emissions. However, in the context of this update's focus on reliability during peak demand periods and the limitations of the simplified methodology, large-scale solar was not included in the adequacy assessment.

Generator availability

The Commission received updated information from licensees regarding generator availability in the Darwin-Katherine power system (Table 4). The Commission notes this is an indicator of past, not future, availability and can fluctuate from year to year.

Table 4: Change in generator availability assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update

Power station	Change – generation availability (%)
Pine Creek power station	- 1.27
Hudson Creek power station	0.00
Shoal Bay	0.00
CIPS	- 1.81
Katherine power station	3.46
Weddell power station	5.60

The most notable changes in generator availability in the Darwin-Katherine power system are:

- increased availability at Katherine and Weddell power stations
- slightly lower availability at CIPS and Pine Creek power station.

While the biggest changes, at Katherine and Weddell power stations are in a positive direction, minor declines at CIPS and Pine Creek power station may offset gains slightly. These changes suggest previous reliability assessments for the Darwin-Katherine power system would not materially change, however this cannot be confirmed without detailed modelling.

The power station availability information shown in Table 4 does not show future availability, including for CIPS, and therefore does not take into consideration any potential change in availability following life extension works, which the Commission understands would be reduced based on discussions with various stakeholders including Territory Generation and PWC System Control.

Operational considerations – the reality of aging generation assets

As discussed above, the life extension works to generators at CIPS may improve reliability to some degree based on an assessment of the retirement date changes as they relate to the 2023 NTEOR modelling. However, in addition to availability limitations, operational limitations of aging generators remain a concern for the Commission.

The Commission has seen evidence to suggest some generators can only operate within a narrow range of capacity due to technical limitations, and some start-up and ramp-up constraints are likely to impact dispatch flexibility, reducing their ability to respond to system fluctuations. As intermittent renewable penetration grows, flexible generation will be increasingly critical, which is a challenge for aging gas turbines.

While life extensions to delay retirements may be the only viable short-term option given the timing of the challenges ahead, they will not fully resolve all issues, including as increased flexibility requirements may exceed their capabilities. However, the Commission does not have visibility of the business case to know whether it is the most appropriate solution, noting life extension works will still take time, come at a cost and will see the larger, less efficient and potentially less flexible generators in service longer[6]. The long-term value of these aging generators remains uncertain as the power system continues to evolve, with increasing levels of renewable generation requiring greater system adaptability.

Supply conclusion

Based on its assessment of updated information, as discussed above, the Commission considers the risk of reliability shortfall has increased in the short term and decreased to some extent in the medium term with life extension works on key generators at CIPS. However, there is a high degree of uncertainty on the impacts (positive and negative) given the lack of information provided to the Commission by Territory Generation. Despite this, the overall assessment remains unchanged with a medium risk of not meeting customer demand in the short term and a high risk in the medium to long term. Operational constraints on aging generators remain a concern, particularly with regard to flexibility limitations. Future supply reliability and security remains dependent on committed investment in, and delivery and operation of, new generation and supporting technologies.

6 The Commission does not have visibility of Territory Generation's business case for the life extension works to enable the Commission to form a view on whether this is the most appropriate solution.

2 Alice Springs

Table 5 provides an overview of the Commission's assessment of the risk (or likelihood) of not meeting customer demand in the Alice Springs power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those that have a material change on the assessed risk.

Table 5: Risk of not meeting customer demand in the Alice Springs power system

Risk of not meeting customer demand		
Short term	Medium term	Long term
Medium	Medium	Medium
Change since the 2023 NTEOR		
0 – 3 years	4 – 6 years	7 – 9 years
Territory Generation's retirement of units 8 and 9 at the RGPS has increased the risk of not meeting customer demand in the short term, with the delayed retirement of the remaining units at RGPS doing little to materially impact this assessment. The risk remains at medium.	Derated units at the Owen Springs power station (OSPS) during summer periods slightly increases the risk of not meeting customer demand in the medium term. The risk remains at medium.	Derated units at the OSPS during summer periods slightly increases the risk of not meeting customer demand in the long term. The risk remains at medium.

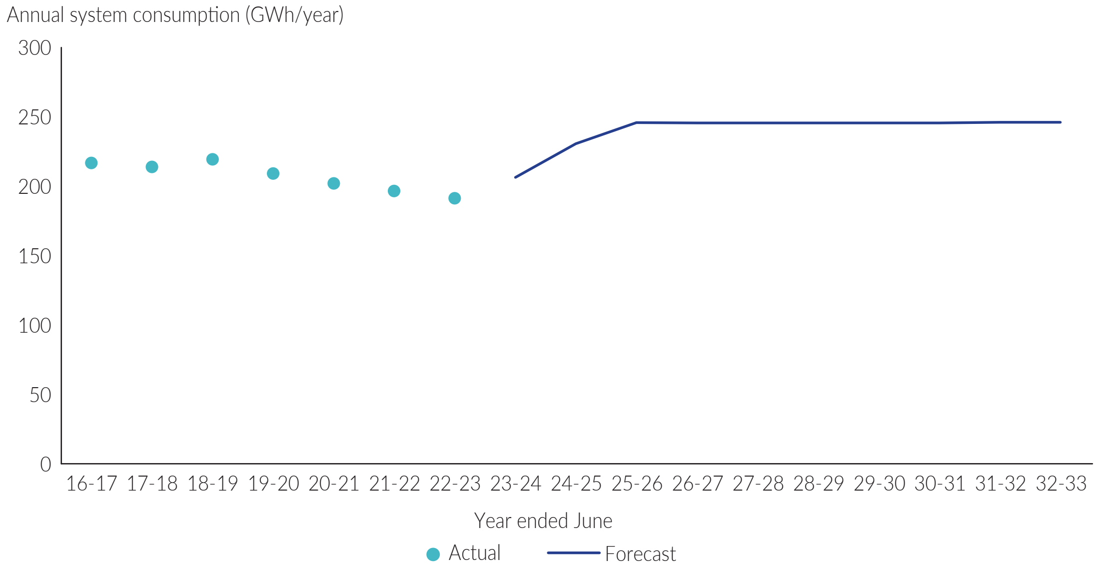
Demand

Summary of 2023 NTEOR findings

Annual electricity consumption

The 2023 NTEOR noted that electricity consumption in the Alice Springs power system had declined in recent years due to increasing rooftop solar PV. However, a new industrial load, expected to connect in 2024-25, was forecast to result in an increase in total consumption before growth stabilised, as shown in Figure 8.

Figure 8: Historical and forecast annual system consumption for Alice Springs as reported in the 2023 NTEOR, 2016-17 to 2032-33[1]



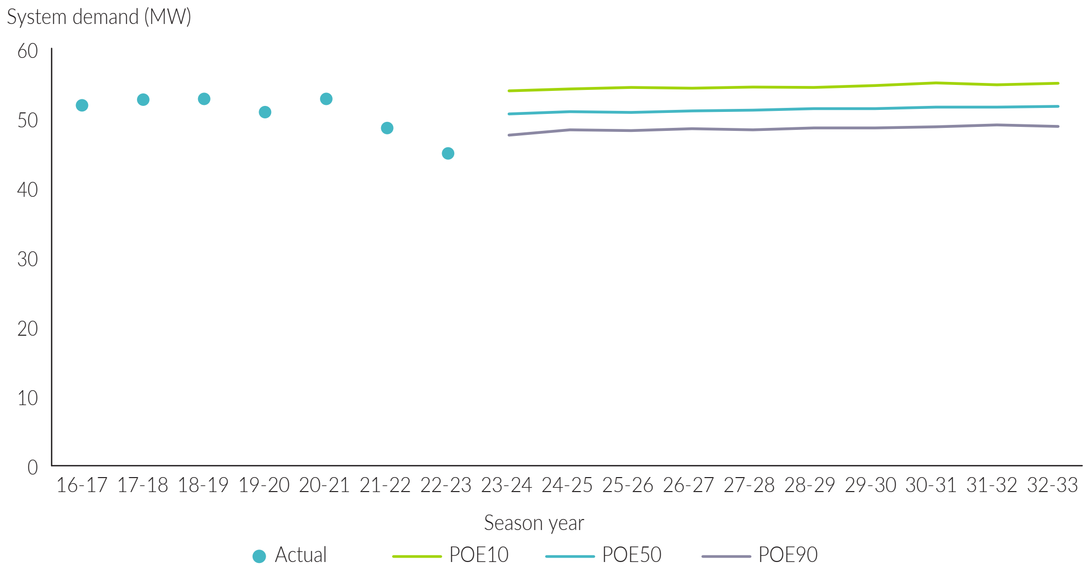
1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

Maximum demand

Historically maximum system demand in the Alice Springs power system occurred in the afternoon during summer, primarily due to airconditioning loads.

The 2023 NTEOR forecasted a short-term increase in maximum demand due to a new industrial load, with maximum demand expected to remain relatively flat after 2025-26, as shown in Figure 9. Solar PV penetration was forecast to push peak demand later into the evening.

Figure 9: Historical and forecast maximum system demand for Alice Springs by season years (year ending 31 August) 2016-17 to 2032-33, as reported in the 2023 NTEOR[1]



1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

Minimum demand

The 2023 NTEOR reported that minimum system demand in the Alice Springs power system has been declining steadily and in 2022-23, occurred in the middle of the day due to high PV generation.

While the new industrial load was forecast to raise minimum demand in the near term, the long-term trend remained downward, as shown in Figure 10. By the end of the outlook period, minimum demand was projected to continue occurring around midday.

Figure 10: Annual historical and forecast minimum system demand for Alice Springs, season years (year ending 31 August) 2016-17 to 2032-33, as reported in the 2023 NTEOR

1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

2024 NTEOR Update

Maximum demand

The Alice Springs power system recorded a maximum demand of 54.7 MW in January 2024, a significant increase from the 44.92 MW recorded in 2022-23. Notably, this demand exceeded the 2023 NTEOR POE10 forecast of 53.94 MW, highlighting that peak demand conditions in 2023-24 were more extreme than forecast.

Minimum demand

In 2023-24, minimum demand in the Alice Springs power system was recorded at 6.6 MW in April 2024, slightly higher than the 5.68 MW record minimum observed in 2022-23. The recorded minimum demand was just above the POE90 forecast of 6.51 MW in the 2023 NTEOR but lower than the POE50 (7.42 MW) and POE10 (8.32 MW) forecasts.

The Commission previously expected a large industrial load, anticipated to connect to the Alice Springs power system, would contribute to minimum demand and help mitigate system security issues. However, based on new information the Commission understands there is a possibility this load may be constrained at times of minimum demand in order to maintain system security. If this is the case, the minimum demand challenges in Alice Springs will not be deferred as previously forecast but will instead remain an immediate and ongoing concern for power system security.

Electric vehicles, behind-the-meter solar and batteries, and economic and climate drivers

Consistent with the Darwin-Katherine power system discussion, the Commission finds no material changes to these demand drivers since modelling was undertaken for the 2023 NTEOR.

Block loads

Block loads are the most notable demand-side change since the 2023 NTEOR. The Commission requested updated block load information from PWC. The new information reflects timing adjustments to an industrial load's connection schedule.[7]

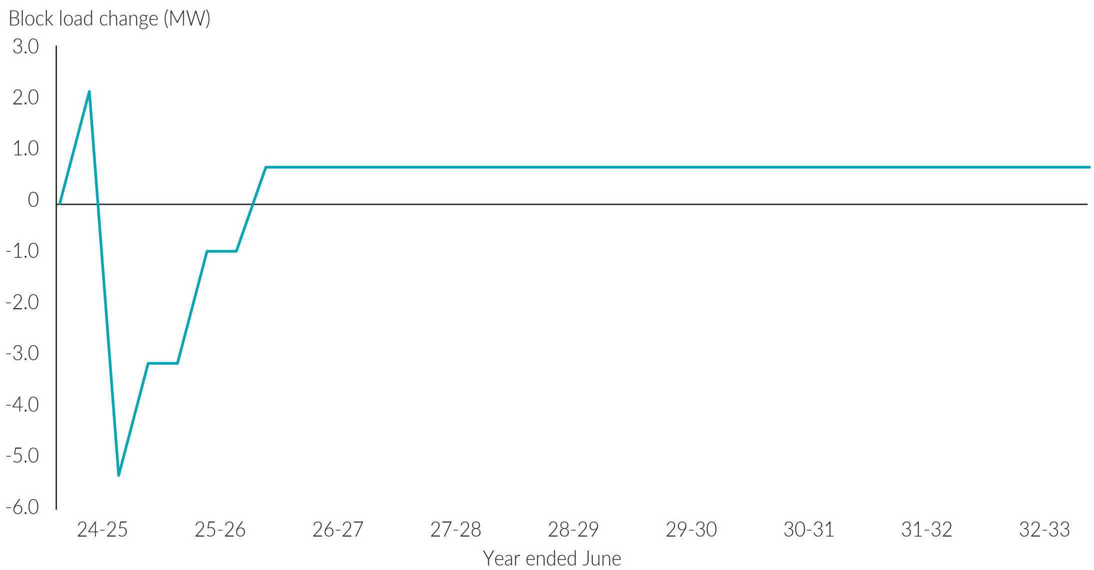
Figure 11 and Table 6 illustrate the changes in block load assumptions for the Alice Springs power system between the 2023 NTEOR and 2024 NTEOR Update, based on updated information from PWC.

Figure 11 shows the quarterly change (increase or decrease in MW) over time, allowing for a visual representation of the magnitude and timing of changes. The chart does not display total block load demand or system demand, only the variation in block load assumptions.

Table 6 summarises the average change in block load assumptions on a financial-year basis. The values represent the average of the four quarters within each financial year.

While both the chart and table reflect the same underlying changes, they are not directly comparable due to differences in the level of granularity (quarterly vs. annual averages). These figures provide an indicative, high-level view of the adjustments rather than a precise measure.

Figure 11: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2024 NTEOR Update, from 2024-25 to 2032-33



7 Recent updates suggest the industrial load's connection is running behind schedule, and there is a level of uncertainty regarding revised timings.

Table 6: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2024 NTEOR Update, on a financial-year basis from 2024-25 to 2032-33

	Change (MW)
2024-25	- 1.6
2025-26	- 1.1
2026-27	0.7
2027-28	0.7
2028-29	0.7
2029-30	0.7
2030-31	0.7
2031-32	0.7
2032-33	0.7

Under a POE50 scenario, the maximum demand in Alice Springs was forecast in the 2023 NTEOR as between 50.6 and 51.7 MW over the outlook period. The incremental increase of 0.7 MW in total load is considered negligible compared with the forecast maximum demand. Accordingly, the impact on system reliability and planning from this small increase is considered immaterial.

Demand conclusion

Based on its assessment of updated information, as discussed above, the Commission finds no material change in demand drivers since the 2023 NTEOR. As a result, any changes in the supply-side assessment do not need to factor in new demand considerations.

However, the Commission notes new information indicating a large industrial load, previously expected to contribute to increasing minimum demand, may not provide the forecast increase. If this load is routinely constrained off during periods of minimum demand to assist with system security, the anticipated delay in minimum demand challenges will not eventuate. Instead, these challenges will persist as an immediate and ongoing issue, requiring ongoing operational management and potential future interventions or investments.

Supply

Summary of 2023 NTEOR findings

The Alice Springs power system was forecast to face increasing reliability risks due to generation units at the end of their life cycle, high assumed generator outage rates and non-optimised maintenance scheduling.

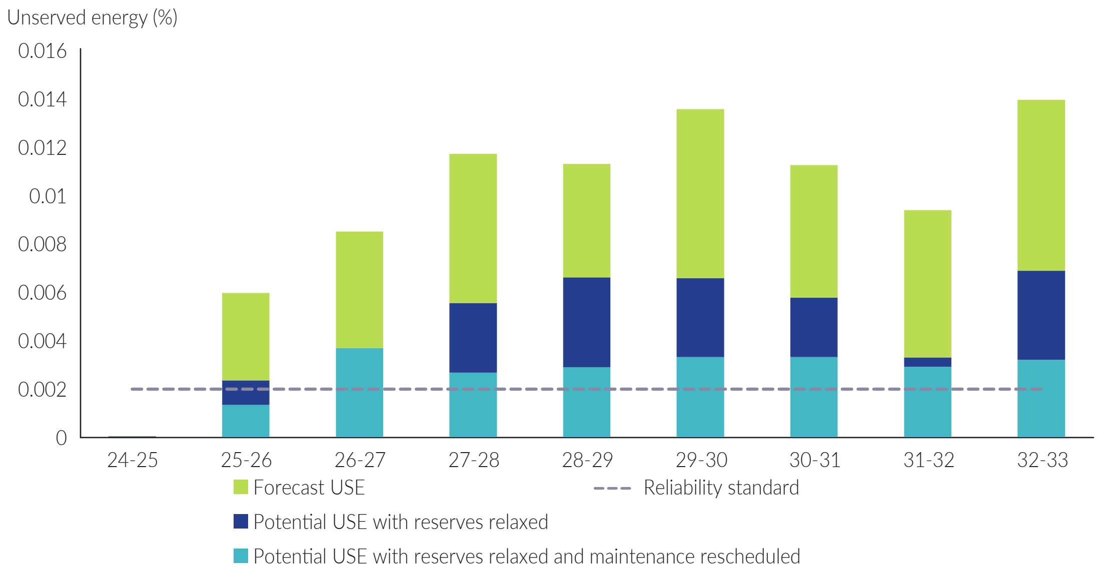
The 2023 NTEOR highlighted the following key supply-side risks:

1. **Short-term reliability risks (2023-24 to 2025-26)** – RGPS was expected to retire by the end of 2025, removing around 35 MW of capacity from the system. The OSPS, which was expected to become the primary dispatchable generator in the region, had high assumed outage rates, posing a risk to system reliability. Modelling showed a heightened risk of not meeting customer demand from 2025 onwards, particularly if OSPS high outage rates persisted or worsened.

2. **Long-term challenges and generation adequacy risks** – the retirement of RGPS without committed replacement capacity increased reliability risks from 2026 onward. The high reliance on OSPS, combined with its maintenance challenges, indicated a potential need for new generation investment in Alice Springs. Renewable integration (primarily rooftop solar) continued to increase, contributing to minimum demand issues and the need for greater system flexibility.

The supply-side risks to customer reliability are reported in the form of forecast unserved energy and are shown in Figure 12, as reported in the 2023 NTEOR.

Figure 12: Forecast reliability, Alice Springs system, 2024-25 to 2032-33, as reported in the 2023 NTEOR



The forecast showed that without investment in new capacity,[8] Alice Springs was potentially at a higher risk of not meeting customer demand.

2024 NTEOR Update

Generation capacity

Since the 2023 NTEOR Territory Generation has:

- revised the summer capacity of OSPS units 5 to 14 from 4.1 MW to 3.9 MW per unit, reducing overall system capacity by about 2 MW
- permanently removed RGPS units 8 and 9[9] from service, reducing capacity by 18 MW
- deferred the retirement of RGPS units 3 to 7 from December 2025 to December 2026,[10] retaining 22.4 MW of capacity for an additional year.

8 No committed power station upgrades or projects were identified at the time of modelling for the 2023 NTEOR.

9 Territory Generation advised unit 9 at the RGPS has been decommissioned (in a March 2025 update), however did not provide a retirement date. The Commission has used 30 January 2024, which aligns with the date the generator started a forced outage, as reported in PWC System Control's long-term risk notice for Alice Springs.

10 RGPS retirement dates have been provided by Territory Generation, however it consistently advises the dates are not firm and subject to reliable operation of the OSPS.

While Territory Generation advised the retirement of the remaining units at RGPS (units 3 to 7) has been deferred from December 2025 to December 2026, and this delay appears to extend an additional 22.4 MW of capacity for another year, the practical usefulness of this capacity remains highly uncertain due to ongoing operational constraints.

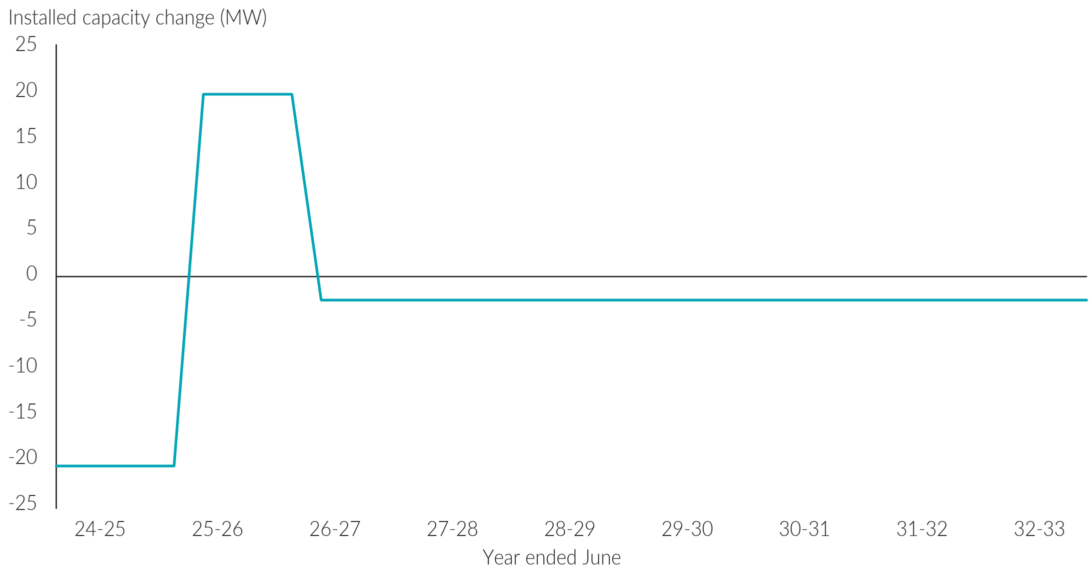
Risk notifications issued by PWC System Control indicate that RGPS has been experiencing significant forced outages and is under restrictions, which materially impact its available capacity. Given these constraints, the Commission considers the deferred retirement of RGPS is unlikely to have a material impact on generation adequacy or the risk of not meeting customer demand in the short term. While the extension nominally increases available capacity on paper, the practical reliability of these aging units remains highly questionable, and their contribution to system adequacy will likely remain limited.

Figure 13 illustrates the changes in installed summer capacity of thermal generation between the 2023 NTEOR and 2024 NTEOR Update, based on updated information from licensees.

Figure 13 shows the increase or decrease in installed summer capacity (MW) over time. The chart does not display total generation capacity, only the variation in assumptions between the two reports. The x-axis represents time, with data points for each quarter within each financial year, while the y-axis represents the change in installed summer capacity of thermal generation (MW), rather than absolute capacity values.

This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

Figure 13: Change in total MW of thermal generation capacity (summer) assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update, from 2024-25 to 2032-33



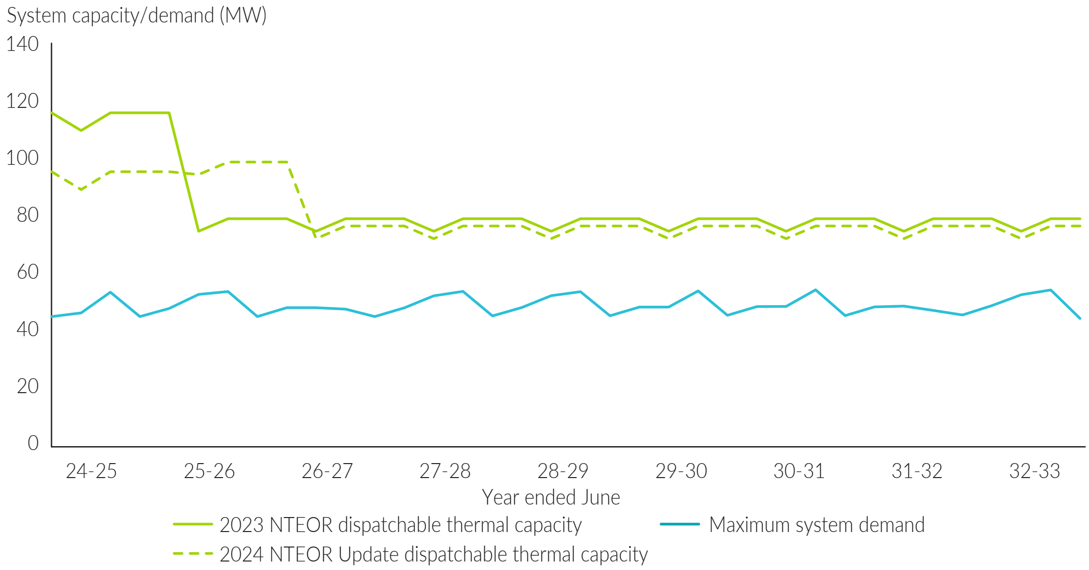
The retirement of RGPS units 8 and 9 in late and mid 2023-24, respectively, increases short-term risks as it reduces available generation capacity. The deferral of RGPS retirement to 2025-26 somewhat offsets earlier losses, at face value improving the reliability outlook in the short term overall. However, as discussed above, this is unlikely to have a material impact in practice.

In the medium to long term, risks remain elevated (medium) due to the level of capacity at the OSPS and lack of new committed generation.

Territory Generation has indicated plans to install a new generator at OSPS (with a summer capacity of 12 MW), which could help mitigate reliability concerns. However, this is not considered a committed project for the purpose of this outlook update as it is yet to receive final approvals.

To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 14). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments only account for summer dispatchable capacity (not seasonal as per the original chart). This coarse visual assessment does not account for generation availability changes but offers a useful high-level comparison.

Figure 14: Forecast dispatchable thermal capacity and maximum demand, Alice Springs power system, 2024-25 to 2032-33



Generator availability

The Commission received updated information from licensees regarding generator availability, which is shown in Table 7. The Commission notes this is an indicator of past, not future availability, and can fluctuate from year to year.

Table 7: Change in generation availability assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update

Power station	Change – generation availability (%)
OSPS	2.64
RGPS	8.44

Improvements in OSPS and RGPS availability are positive developments. The availability improvements may partially mitigate reliability risks but do not eliminate concerns in the region.

Similar to comments made about the aging generators at CIPS and consistent with the discussion above, deferring the retirement of RGPS may ensure total capacity in the power system is at a certain level but that capacity must be reliable in practice and, if necessary, flexible to the power system's needs. Further, in addition to the outages already discussed, the Commission considers the RGPS continues to be at risk of unexpected or prolonged outages, given its age and operational limitations.

Non-reliable periods

In the past, there has been limited visibility of the tight demand-supply conditions faced by the Territory's power systems. While PWC System Control issues non-reliable notices to system participants when available generation capacity approaches critical levels, typically due to a combination of forced and planned generator outages coinciding with high demand periods, these were not publicly available, meaning that while the Commission forecasted these risks in its NTEOR reports, their occurrence was largely invisible to those outside the industry.

For those without visibility of PWC System Control's notices, it may have seemed that such risky periods never occurred, as the lights stayed on. However, in reality, the Territory's power systems have faced periods of operational stress, which has required active intervention and careful management by PWC System Control behind the scenes to ensure real time security and reliability.

PWC System Control now publishes non-reliable notices on its website,[11] which usefully provides transparency into the real-time pressures facing the system. Notably, during 2024-25, the Alice Springs power system has been subject to multiple non-reliable notices after having none for the previous four years. This suggests a tightening demand-supply balance and may be an early warning sign of greater risks ahead. Similarly, the Darwin-Katherine power system has also been subject to non-reliable notices during 2024-25, reinforcing the challenges faced in ensuring adequate generation availability. While these notices indicate intervention strategies have so far succeeded in preventing supply shortfalls, they serve as a critical reminder that the system is operating under increasing strain, and reactive solutions alone may not be sufficient in the long term.

Supply conclusion

Based on its assessment of updated information, as discussed above, the Commission considers the short-term reliability concerns regarding the Alice Springs power system have increased with the retirement of units 8 and 9 at RGPS, and retirement deferral of the remaining units at RGPS has little material impact on improving the situation. The risk of not meeting customer demand remains at medium in the short term.

The medium to long-term risks of not meeting customer demand also remain assessed at medium risk, noting Territory Generation's proposed OSPS expansion (12 MW) may help, but its impact is contingent on final approvals and associated delivery and operation. Without further generation investment and or greater optimisation and utilisation of the current generation, the Alice Springs power system remains vulnerable to system reliability issues across the outlook period.

11 https://www.ntesmo.com.au/non-reliable-risk-notices.

3 | Tennant Creek

Table 8 provides an overview of the Commission's assessment of the risk (or likelihood) of not meeting customer demand in the Tennant Creek power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those that have a material impact on the assessed risk.

Table 8: Risk of not meeting customer demand in the Tennant Creek power system

Risk of not meeting customer demand		
Short term	Medium term	Long term
Low	Low	Medium
Change since the 2023 NTEOR		
0 – 3 years	4 – 6 years	7 – 9 years
No change from the 2023 NTEOR.	No change from the 2023 NTEOR.	Territory Generation's plan to progressively retire five units at the Tennant Creek power station (TCPS) increases the risk of not meeting customer demand in the long term from **low** to **medium**.

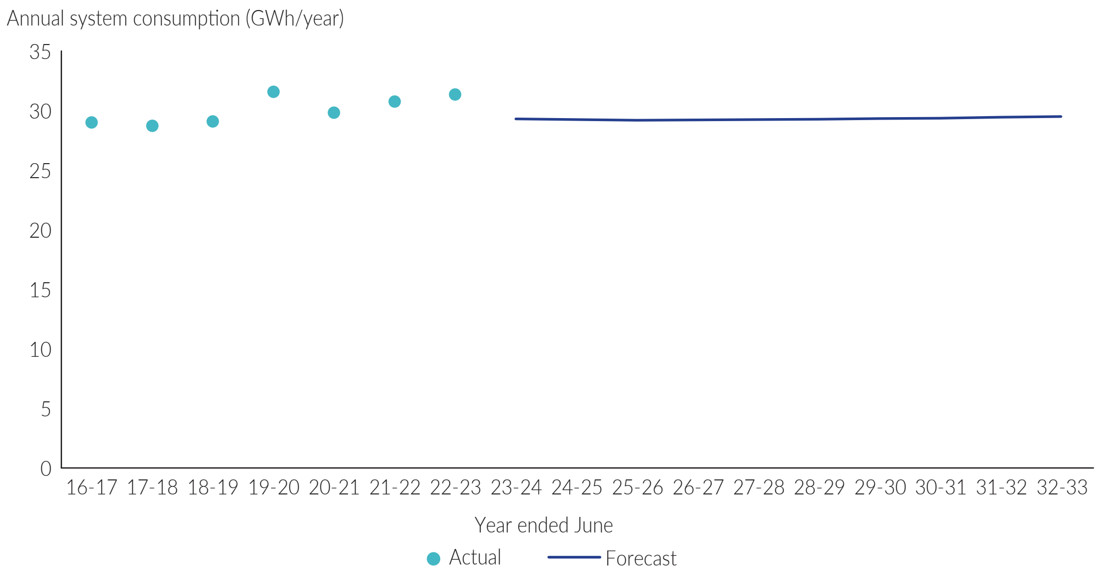
Demand

Summary of 2023 NTEOR findings

Annual electricity consumption

The 2023 NTEOR noted that electricity consumption in the Tennant Creek power system has remained relatively stable in recent years, with only minor fluctuations. This was expected to continue throughout the outlook period, as shown in Figure 15.

Figure 15: Historical and forecast annual system consumption for Tennant Creek as reported in the 2023 NTEOR, 2016-17 to 2032-33[1]

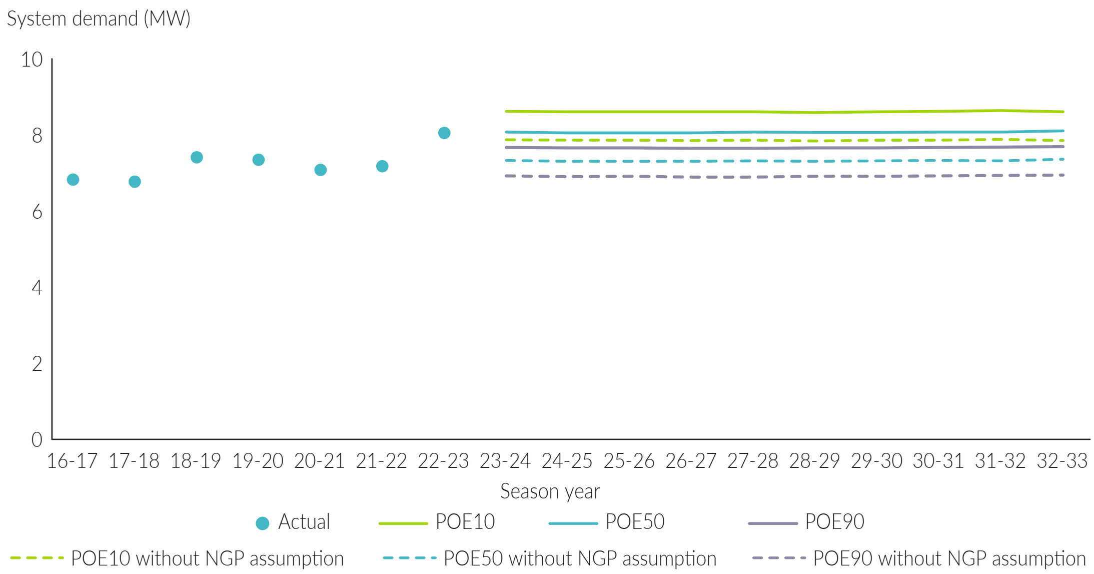


1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

Maximum demand

Historically maximum system demand in the Tennant Creek power system typically occurred in summer, driven by airconditioning loads. In 2022-23, it was recorded at 8.05 MW. Over the outlook period, growth in maximum demand was forecast to remain flat, as shown in Figure 16, with no significant drivers leading to major changes in the forecast.

Figure 16: Historical and forecast maximum system demand for Tennant Creek by season year (year ending 31 August) as reported in the 2023 NTEOR, 2016-17 to 2032-33[1]

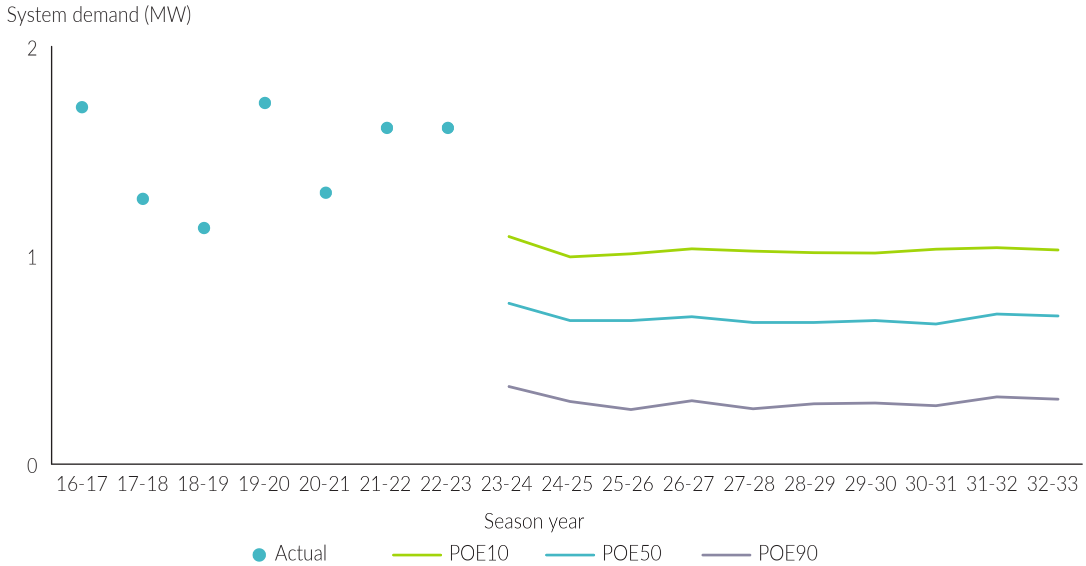


1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

Minimum demand

The 2023 NTEOR reported that minimum system demand in the Tennant Creek power system had shifted from early morning to midday due to increased PV penetration. It was projected to decline over the outlook period, as shown in Figure 17. Given the existing challenges in the Tennant Creek power system, including Tennant Creek's small system size making it particularly vulnerable to fluctuations in demand and supply, it was suggested that further reductions in minimum demand may exacerbate system security risks.

Figure 17: Historical and forecast minimum system demand for Tennant Creek by season year (year ending 31 August) as reported in the 2023 NTEOR, 2016-17 to 2032-33[1]



1 Reproduced from the 2023 NTEOR and includes both actual and forecast data. 2023-24 data is forecast as actuals were not available at the time of publication of the 2023 NTEOR.

2024 NTEOR Update

Maximum demand

The Tennant Creek power system recorded a maximum demand of 6.8 MW in December 2023, a decrease from the 8.05 MW recorded in 2022-23. This actual demand was below the POE90 forecast (7.68 MW) in the 2023 NTEOR, indicating that maximum demand was notably lower than the most conservative forecast scenario.

Minimum demand

Minimum demand in Tennant Creek reached a new record low of 1 MW on 9 September 2024, and was lower than the minimum of 1.61 MW set in 2022-23. This value was within the range forecast in the 2023 NTEOR, which projected a POE90 minimum demand of 0.37 MW, POE50 of 0.77 MW and POE10 of 1.09 MW.

Electric vehicles, behind-the-meter solar and batteries, and economic and weather assumptions

Consistent with the Darwin-Katherine and Alice Springs power systems discussion, the Commission finds no material changes to these demand drivers since modelling was undertaken for the 2023 NTEOR.

Block load

No block loads were considered in the 2023 NTEOR. Following a review of updated information from PWC, this remains unchanged for the 2024 NTEOR Update.

Demand conclusion

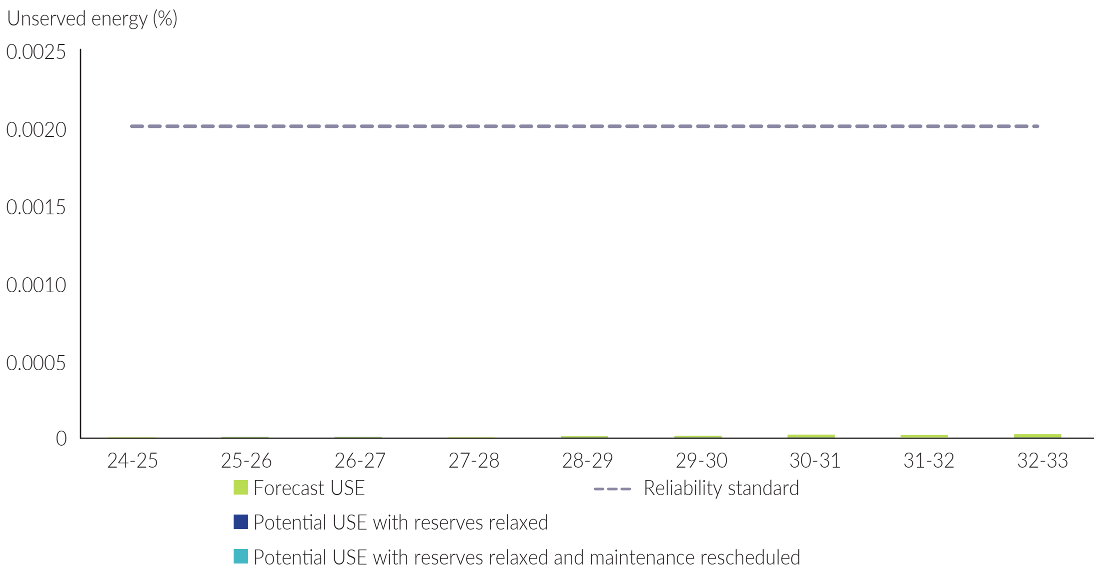
No material changes have been observed in the Tennant Creek power system's demand drivers since the 2023 NTEOR. As a result, the Commission considers that any changes on the supply-side assessment do not need to factor in new demand considerations.

Supply

Summary of 2023 NTEOR findings

The Tennant Creek power system was forecast in the 2023 NTEOR to maintain a substantial surplus of generation capacity throughout the entire outlook period, resulting in no material unserved energy expected across the outlook period, as shown in Figure 18.

Figure 18: Forecast reliability, Tennant Creek system as reported in the 2023 NTEOR, 2024-25 to 2032-33



2024 NTEOR Update

Generation capacity

Since the 2023 NTEOR, Territory Generation has:

- revised the retirement dates for units 1 and 5 at the TCPS to January 2025 (previously advised these retired in December 2023), effectively increasing summer capacity by about 2.2 MW in the first half of 2024-25.
- advised that five additional units (10 to 14) will be progressively retired between 2028-29 and 2030-31, with two units retiring in both 2028-29 and 2029-30 and one in 2030-31. These retirements will reduce available summer capacity by about 4.5 MW, slightly reducing the reserve margin in the later years of the outlook period. Despite this, the Tennant Creek power system is still expected to maintain sufficient capacity to meet forecast demand.
- advised the 'sustainable capacity' of units 19 to 21 at TCPS is reduced.

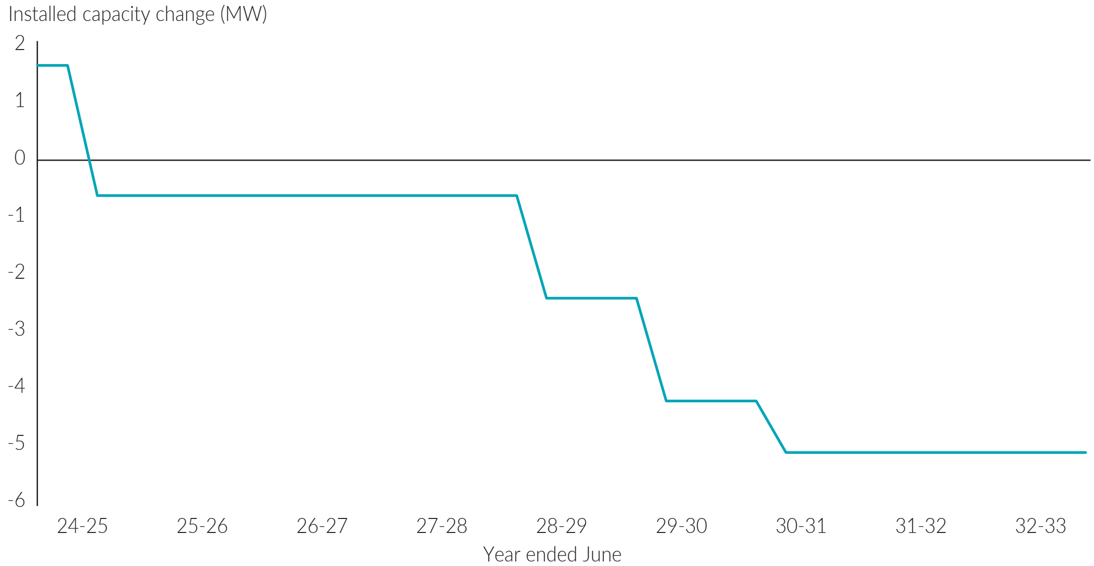
Figure 19 illustrates the changes in installed summer[12] capacity of thermal generation between the 2023 NTEOR and 2024 NTEOR Update, based on updated information from licensees.

Figure 19 shows the increase or decrease in installed summer capacity (MW) over time. The chart does not display total generation capacity, only the variation in assumptions between the two reports. The x-axis represents time, with data points for each quarter within each financial year, while the y-axis represents the change in installed summer capacity of thermal generation (MW) rather than absolute capacity values.

12 Except for TCPS units 19-21, which use 'sustainable capacity' as reported by Territory Generation.

This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

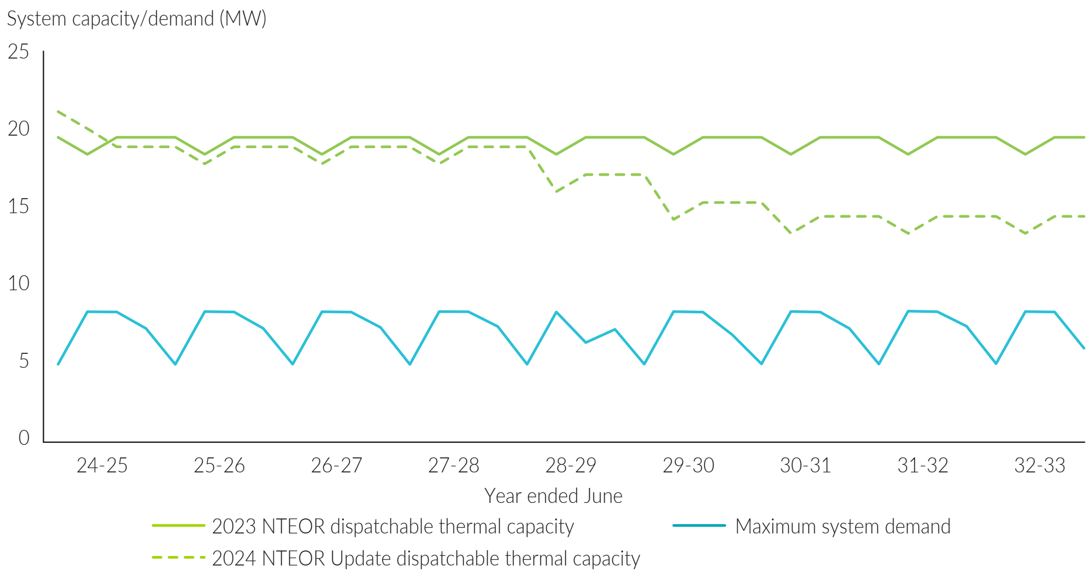
Figure 19: Change in total MW of thermal generation capacity (summer[1]) assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update, from 2024-25 to 2032-33



1 Except for TCPS units 19-21, which use 'sustainable capacity' as reported by Territory Generation.

To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 20). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments only account for summer[13] dispatchable capacity (not seasonal as in the original chart). This coarse visual assessment does not account for generation availability changes but offers a useful high-level comparison.

Figure 20: Forecast dispatchable thermal capacity and maximum demand, Tennant Creek power system, 2024-25 to 2032-33



13 Except for TCPS units 19-21, which use 'sustainable capacity' as reported by Territory Generation.

1 Except for TCPS units 19-21, which use 'sustainable capacity' as reported by Territory Generation.

Generator availability

The Commission received updated information from Territory Generation regarding generator availability, which is shown in Table 9 below. The Commission notes this is an indicator of past, not future, availability and can fluctuate from year to year.

Table 9: Change in generation availability assumptions from the 2023 NTEOR and updated information from licensees for the 2024 NTEOR Update

Power station	Change – generation availability (%)
TCPS	- 6.18

The updated information from Territory Generation indicates a decline in generation availability at the TCPS of just over 6%. This change slightly lowers the effective reserve margin and reduces the amount of generation available to meet customer demand. However, given the Tennant Creek power system was forecast to maintain a comfortable surplus of capacity, this reduction is not expected to have a material impact on system reliability.

Supply conclusion

The Tennant Creek power system remains well-supplied with generation capacity throughout the outlook period despite the newly advised lower output from units 19 to 21 at TCPS and retirement of units 10 to 14 in later years. While generation availability has declined, the overall capacity buffer remains sufficient to ensure system reliability. However, the Commission has cautiously raised its risk assessment of not meeting customer demand from low to medium in the long term.

Appendix: Glossary

AEMO	Australian Energy Market Operator
CIPS	Channel Island power station
Commission	Utilities Commission of the Northern Territory
EV	electric vehicle
MW	Megawatt
NTEOR	Northern Territory Electricity Outlook Report
NTEOR Update	Northern Territory Electricity Outlook Report Update
NTESMO	Northern Territory Electricity System and Market Operator
OSPS	Owen Springs power station
POE10	Probability of exceedance at 10%
POE50	Probability of exceedance at 50%
POE90	Probability of exceedance at 90%
PV	Photovoltaic
PWC	Power and Water Corporation
RESIP	Regulated Electricity System Investment Plan
RGPS	Ron Goodin power station
TCPS	Tennant Creek power station