UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Northern Territory Electricity Outlook Report

2022

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Disclaimer

The Northern Territory Electricity Outlook Report (NTEOR) is prepared using information sourced from participants of the electricity supply industry, Northern Territory Government agencies, consultant reports and publicly available information. The NTEOR is in respect of the financial year ending 30 June 2022 and a 10-year outlook period from 1 July 2022 to 30 June 2032 (outlook period). The Utilities Commission understands the information received to be current as at January 2023.

The NTEOR contains 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 NTEOR 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 NTEOR or 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 review 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.

About this report

Since 2018, the Utilities Commission of the Northern Territory (Commission) has published an annual Northern Territory Electricity Outlook Report (NTEOR), which focuses on the system demand and supply outlook for the Darwin-Katherine, Alice Springs and Tennant Creek power systems (power systems).

This 2022 NTEOR presents electricity consumption, maximum and minimum demand, and generation adequacy forecasts for the Territory's power systems over a 10-year outlook period from 1 July 2022 to 30 June 2032 (outlook period). It focuses on a single business-as-usual scenario, which forecasts and considers consumer demand over the outlook period against the current operating state of the power system, including committed new investments[1] and scheduled decommissioning (discussed in detail in Appendix A1).

The outlook includes:

- annual system electricity consumption and maximum and minimum system demand forecasts for the Darwin-Katherine, Alice Springs and Tennant Creek power systems, and subregions within the Darwin-Katherine power system
- future supply projections, including committed new projects and scheduled decommissioning of existing generators
- generation supply adequacy assessments.

The main purpose of the NTEOR is to inform decisions by government, licensees and investors by providing forecasts of prospective trends in system demand and supply reliability to identify challenges, gaps or opportunities.

The 2022 NTEOR was produced predominantly by the Australian Energy Market Operator (AEMO) on behalf and with the assistance of the Commission, in accordance with section 45 of the *Electricity Reform Act 2000*, and is restricted to the Darwin-Katherine, Alice Springs and Tennant Creek power systems. The Commission supports the analysis, conclusions and recommendations made on its behalf by AEMO.

The inputs to the NTEOR modelling, and subsequent modelling outcomes, are heavily reliant on the quality, accuracy, completeness and currency of data and information provided by licensees and stakeholders. The Commission notes in relation to the challenges of developing assumptions for the next ten years that, in the changing power systems of the Territory:

- there are gaps between documented and published information and data, and what happens in practice
- maintenance schedules for the next ten years will change
- there are plans, projects, practices and policies that are proposed or being contemplated, but are not yet considered to be committed.

1 Committed investments, projects, developments or generation are those the Commission considers have demonstrated sufficient development progress and are highly likely to proceed, with major milestones reached, such as a Commission-issued licence to operate in the Territory's electricity supply industry, relevant PWC connection agreement executed, final investment decision reached (private industry projects), and approved government funding (public projects). The Commission intentionally takes a conservative approach in order to capture an accurate business-as-usual scenario.

Each year it is increasingly challenging to lock down what is essentially a continually moving and uncertain target.

Nonetheless, AEMO sought to model the current operating state of the power systems, including the associated controls applied by Power and Water Corporation (PWC) System Control, however neither AEMO nor the Commission has considered whether the current operating assumptions (detailed in Appendix A1) are appropriate in terms of risk aversion or operating cost, as it is outside the scope of this report. The outlook seeks to identify reliability risks relative to tolerance however, it does not recommend specific solutions to mitigate those risks.

The generation adequacy assessments in the 2022 NTEOR consider whether forecast generation capacity, or other technologies and solutions, are expected to deliver the level of reliability comparable with the reliability standard in the National Electricity Market (NEM), which the Commission has adopted in the absence of a formal reliability standard in the Territory. The NEM reliability standard specifies that expected unserved energy (USE)[2] should not exceed 0.002% of total electricity consumption in a NEM region in any financial year.[3]

AEMO deployed a methodology similar to that used in previous years, and scrutinised, consulted on and updated the inputs as considered necessary to reflect more recent power system outcomes and expectations. Further detail about the performance assessment can be found in Appendix A3.

The Commission is aware of other demand modelling undertaken in respect of the Territory's power systems, including by PWC. This modelling may not align with AEMO's modelling due to differences in methodology and assumptions, with the Commission intentionally taking a conservative approach in order to capture an accurate business-as-usual scenario.

Consistent with last year, the Darwin-Katherine power system was split into three subregional nodes (nodes) for modelling purposes (Darwin; Manton, Batchelor and Pine Creek; and Katherine). By modelling each node separately, the NTEOR can better identify challenges and opportunities in each subregion in addition to the broader power system analysis. However, AEMO and the Commission listened to stakeholder feedback and made improvements to the 2022 NTEOR methodology to ensure overall Darwin-Katherine power system forecasts are as robust as subregional node forecasts. Discussion regarding this approach is included in Appendix A1.

2 USE is electricity that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply) as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand. 'Expected' refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

3 In the NEM this covers the interconnected electricity network (excluding off-grid and islanded systems) in Queensland, New South Wales, Victoria, South Australia, and Tasmania. For the purpose of this report, the NEM's 0.002% reliability standard is used for comparison. The 'interim reliability measure,' announced on 20 March 2020 by the Energy Security Board, is not used in this report.

Key findings and recommendations

Transitioning to renewables is critical, but it is not easy. Electricity networks and systems everywhere are currently working out how to transition from fossil fuels while keeping electricity supply reliable and secure, and at the same time seeking to minimise the cost of the transition.

The challenge in the Territory is greater than elsewhere in Australia. The Territory's three power systems are very small, isolated, and have a lack of diversity of potential renewable energy sources (almost exclusively solar photovoltaic [PV]).

In an electricity system, demand and supply must be perfectly matched in real time or the system can collapse. In the past, demand fluctuations have been managed by the ability of synchronous generators (in the Territory, largely gas generators) to ramp up or down to match changing demand and provide important services that help the system maintain a stable frequency and voltage. Solar PV generation (without storage) does not have this capacity. Further, as solar PV generation is non-synchronous and intermittent, it can introduce supply fluctuations and does not currently provide some of the services needed to maintain a secure system.

The Territory is also seeing large numbers of residential and commercial customers connecting rooftop solar PV systems. These systems can help reduce emissions and costs for those customers, but are not subject to the same technical requirements and control as traditional larger generators. They are also reducing minimum demand from the system during daylight hours, which brings new technical challenges that need to be managed.

Several of the current large gas generators in Darwin are also aging and due to be retired within the next few years. This provides both an opportunity and a challenge as part of the transition to renewable generation.

As a result, this increased renewable generation introduces increased complexity in managing the system and there will be a need for significant new investment to keep the system reliable and secure. One of the reasons some new, already constructed large-scale solar PV projects in the Territory have not been connected to the network is due to concerns about the impact on system security and reliability were they to be connected now without additional supporting services.

There are ways to deal with all of these challenges. The Commission is an economic regulator not a technical adviser, but it is likely the solution to this challenge will at least involve a combination of batteries, synchronous condensers, network changes and demand side management.

Significant new investment will be needed to successfully achieve a transition to greater renewable generation.

The Territory Government has acknowledged the challenge and urgency, and is responding. A range of important plans are under development to address the issues, but few of them have so far progressed to the investment stage that enables the Commission to include them in the forecasts contained in this report.

There is little change to the findings and message in the 2022 NTEOR compared to previous reports, other than the challenges and emerging risks to the Territory's power systems are another year closer to materialising in the absence of appropriate, committed, funded and timely delivered solutions.

The 2022 NTEOR forecasts risks to maintaining a secure Darwin-Katherine power system as early as 2026-27 (only three years away) due to falling minimum demand during the day as a result of increasing amounts of electricity from uncontrollable residential and commercial rooftop solar PV systems. Further, should a solution or solutions not be delivered in time to address the expected retirement of 185 megawatts (MW) of generation capacity at the Channel Island power station (47% of the current generation summer capacity in the Darwin-Katherine power system), customer demand may not be met within four years (2027-28).

While to a lesser extent, the Alice Springs power system is also forecast to have challenges meeting customer demand while maintaining a secure power system over the outlook period. This is due in part to the expected high outage rates (low availability) of newer generation at the Owen Springs power station (OSPS) in the initial years of the outlook period, followed by the expected retirement of the Ron Goodin power station (RGPS) from the end of 2025.

These challenges signal the need for decisions to be made and actioned as a priority, noting any solution involving assets such as new generation or storage involves long lead times for sourcing and delivery, which is particularly challenging at present as supply chains struggle to meet worldwide demand. History has also shown the difficulties the Territory faces in finding appropriate expertise and support, and the significant time it can take to commission and test new equipment following installation. Examples include Territory Generation's new generation and battery energy storage system (BESS) in Alice Springs, and the new large-scale solar farms in Darwin-Katherine, with most of these projects still not fully operational or suffering from teething issues some years after installation.

The Commission has been warning for several years that delays in meeting the emerging challenges and risks to the Territory's power systems means less time to respond, which may increase risks and costs, and ultimately negatively impact Territory electricity consumers and taxpayers. It also reduces options to take advantage of opportunities. Given the risks are now forecast to emerge within the next three to four years, the Commission reiterates action and investment decisions are needed now.

The Commission acknowledges the Territory Government has been working towards addressing the challenges and emerging risks to the Territory's power systems and its target of 50% renewable energy by 2030. The Commission is also aware of Territory Generation's investment plans, although the plan is not approved beyond the short term according to its 2023-24 statement of corporate intent.

Relevantly, the Minister for Renewables and Energy recently wrote to the Commission to advise of Government's activities, which includes a review of power system security risks for the Darwin-Katherine electricity system, preparation of a coordinated plan to integrate renewables over the 2023-24 to 2025-26 period and initiating the development of an integrated system plan with a 10-year outlook. The Commission was also advised of market design and other considerations and notes the 2023-24 Territory Budget allocates funding to progress electricity market reforms, for an Electricity Market Reform Implementation Taskforce, and for the Darwin-Katherine Electricity System Plan, including $12 million to undertake planning and head works to develop a renewable energy hub. While this commitment and progress is encouraging, the Commission notes many investment, governance and market decisions still need to be made and implemented.

The Commission notes the urgency and lack of policy certainty in the Territory is likely to make it more difficult to attract private industry investment in the electricity supply industry without projects being underwritten by the Territory Government. Notwithstanding this risk, the Commission encourages the Territory Government to utilise private investment to help address some of these challenges and risks. Private investment can encourage innovation, share the risk and help deliver the extremely large scale of investment needed within the Government's budget constraints.

The Commission is encouraged by the Territory Government's progress over the last 12 months, and its acknowledgement of the challenges and urgency. The Commission considers it is now time to increase the momentum and move from plans to committed investment decisions.

The next section sets out the specific 2022 NTEOR findings by power system.

Darwin-Katherine

- Electricity consumption from the Darwin-Katherine power system increased in 2021-22 primarily due to higher temperatures experienced across the region. Consumption from the system is forecast to decline over the outlook period due to increases in residential and commercial rooftop solar PV systems (distributed PV), although expected new industrial loads are forecast to reverse the decline for the first four years of the outlook period.
- Maximum system demand is forecast to increase over the outlook period with increases in the short term due to expected new industrial loads. The timing of maximum system demand is expected to transition from mid-afternoon to after sunset by the end of the outlook period.
- Minimum system demand is forecast to decline to below 40 MW by the end of the outlook period due to the growth in distributed PV. This may cause system security implications without further measures to mitigate this risk.
- A number of units at the Channel Island power station (CIPS) totalling 185 MW of capacity are scheduled to retire from 2026-27. These retirements are partially offset by currently committed generation, including Territory Generation's Darwin BESS and CIPS-10 unit at the CIPS, and six large-scale solar power stations that have been built, but are not yet fully operational.
- As a result of the retirements at the CIPS, and despite the retirement of units at the Katherine power station (KPS) being 'pushed' to outside of the outlook period in the 2022 NTEOR compared with the 2021 NTEOR, expected USE is forecast to increase, significantly exceeding the adopted reliability standard from 2027-28. This signals the need for additional investment in new generation, storage, and or demand response, or the deferral of scheduled generator retirements.

- The Commission is aware of several plans proposing new generation capacity in the Darwin-Katherine power system over the outlook period, including the Territory Government's Darwin-Katherine Electricity System Plan, however these plans are not considered to be committed for the purpose of this report. Based on high-level details of the plans, the outlook would likely materially improve if the developments progress.[4] These developments are noted in this report.

Alice Springs

- Electricity consumption from the Alice Springs power system has been generally declining since 2016-17 due to increases in distributed PV. This trend is forecast to continue but is offset by the expected connection of a large load to the Alice Springs network midway through 2023-24.
- Annual maximum system demand is forecast to remain flat following the new load, while minimum system demand is forecast to decrease in line with the uptake of distributed PV.
- Expected USE is forecast to exceed the adopted reliability standard in all years of the outlook period. In the initial years of the outlook period, expected USE is high due to a high assumed unplanned outage rate of OSPS units 5 to 14, based on observed rates over recent years, which highlights possible reliability and operability challenges.
- From 2026-27, expected USE is forecast to be high when compared with the adopted reliability standard due to the assumed retirement of the RGPS. Despite units at the RGPS being at the end of their operational life, they are still forecast to provide reliability improvements while serving as back-up generators and reserve-providing units until their retirement (albeit at additional cost).

Tennant Creek

- Electricity consumption from the Tennant Creek power system and maximum and minimum system demand is forecast to remain relatively constant over the outlook period.
- Substantial surplus generation capacity is forecast over the entire outlook period, resulting in no material levels of forecast USE or issues meeting security requirements.

4 As it is outside the scope of this report, the Commission and AEMO have not given detailed consideration to these plans and make no comment as to whether they are or are not the best solutions to address the forecast reliability issues over the outlook period.

Contents

1 | Darwin-Katherine outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Darwin-Katherine power system as a whole power system, and for each sub-regional node, over the outlook period to 30 June 2032. The chapter also includes discussion regarding minimum system demand implications and plans that may help mitigate identified reliability risks.

Annual electricity consumption

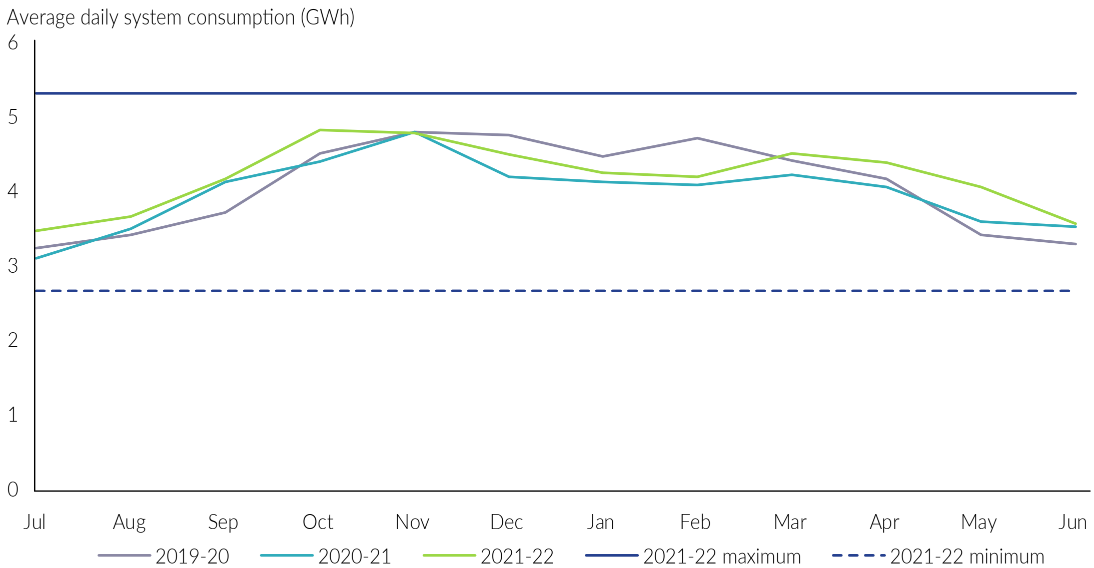
The following section includes recent trends in annual electricity consumption in the Darwin-Katherine power system as a whole system, and for each sub-regional node, along with forecasts over the outlook period.

Electricity consumption observed in 2021-22

In 2021-22, the total annual electricity consumption from the Darwin–Katherine power system (system consumption)[5] was 1,546 gigawatt hours (GWh). This was 5.5% higher than system consumption in 2020-21. This increase is attributed in part to higher temperatures experienced in the Darwin subregion throughout 2021-22. 2021-22 had the highest number of days in recent history where the maximum daily temperature exceeded 32°C, at 275 days. This represents 78 more days than 2020-21 (2021-22: 275 days, 2020-21: 197 days, 2019-20: 244 days, 2018-19: 232 days, 2017-18: 236 days).

Figure 1 shows average daily system consumption, by month, in the Darwin–Katherine power system between 2019-20 and 2021-22. Average daily system consumption in 2021-22 was 4.2 GWh. Maximum and minimum daily consumption were 5.4 GWh and 2.7 GWh, respectively. The month-to-month variability of system consumption in the Darwin–Katherine power system highlights the seasonal variability between the wet and dry seasons.

Figure 1: Average daily system consumption for Darwin–Katherine by month, 2019-20 to 2021-22



5 As defined in A1.7

Recent history and forecast per Darwin-Katherine subregional node

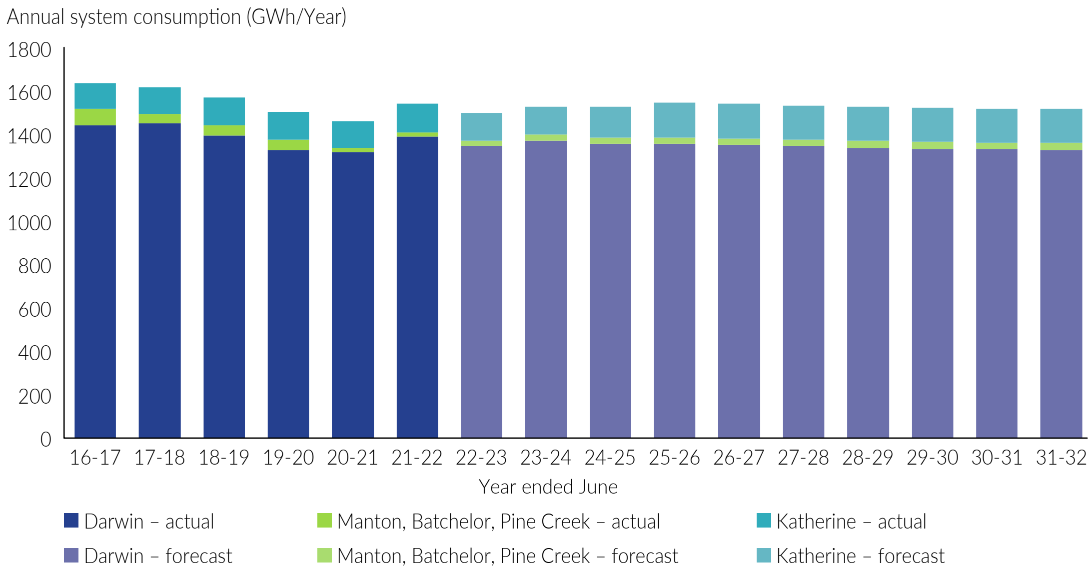
Annual system consumption from the Darwin-Katherine power system has generally declined since 2016-17, noting the increase in 2021-22 was attributed in part to higher temperatures. The trend in declining system consumption has been driven by increases in distributed PV and several industrial activities disconnecting from the network, including infrastructure associated with a liquefied natural gas (LNG) project and mining loads.

System consumption in the Darwin node is forecast to continue to decline over the outlook period. The forecast does not consider any further large loads disconnecting from the power system. In the initial four years of the outlook period, load growth drivers such as expected new industrial loads and growing population are largely being offset by forecast growth in distributed PV (see in Table 2 of Section A1.7.5 for details on block load assumptions). From 2026-27, the decrease in forecast annual system consumption is driven by the forecast growth of distributed PV.

The closure of mining loads has most substantially impacted system consumption in the Manton, Batchelor and Pine Creek node over the past six years. System consumption in the Manton, Batchelor and Pine creek node is forecast to increase over the outlook period, driven by the expected connection of PWC's Darwin River Dam pumping station to the network from October 2023. System consumption in the Katherine node is forecast to increase over the outlook period, driven by the expected Royal Australian Air Force (RAAF) Base Tindal upgrade from January 2025.

Figure 2 shows historical and forecast annual system consumption in the Darwin–Katherine power system.

Figure 2: Historical and forecast annual system consumption for Darwin–Katherine by financial year, 2016-17 to 2031-32



Maximum demand

Maximum system demand forecasts for the aggregated Darwin-Katherine power system and for each of its nodes have been produced independently. The three nodal forecasts are "non-coincident" because their peaks do not necessarily coincide with the time of Darwin-Katherine's aggregated maximum system demand. To ensure consistency across the forecasts, these non-coincident nodal forecasts have been reconciled against the aggregated Darwin-Katherine forecast and are presented as so. The reconciliation approach used can be found in AEMO's connection point forecasting methodology.[6]

Darwin-Katherine forecast

Figure 3 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different probability of exceedance (POE)[7] levels for the Darwin-Katherine power system from 2016-17 to 2031-32.

The 2021-22 maximum system demand of 285 MW occurred during the final weeks of the shoulder season (October) before the wet season and was 1 MW lower than the previous year. Maximum system demand has historically occurred in the final weeks of the shoulder season or during the wet season in the mid-afternoon, driven by loads associated with air conditioning.

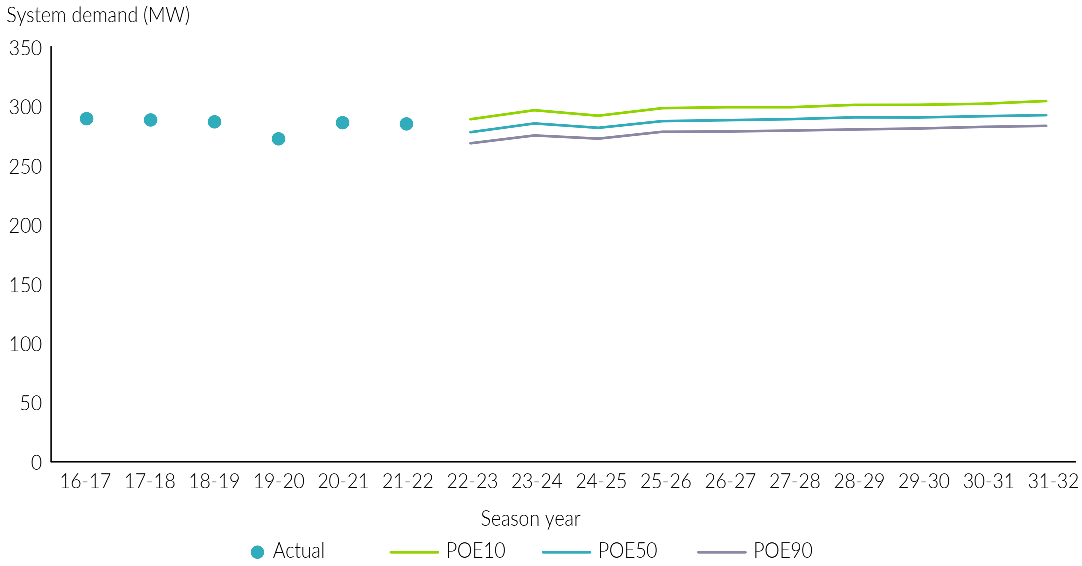
Maximum system demand is forecast to increase over the outlook period, with growth in the short term being attributed to forecast block load connections. The time of maximum system demand is trending later in the day due to the increasing penetration of distributed PV, with the 2021-22 maximum system demand occurring at 16:30.[8] Maximum system demand is forecast to typically occur during the wet season (see section A1.7.2 for season definitions) between 18:30 and 19:30 over the outlook period.

6 AEMO's connection point forecasting methodology can be found here: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/tcpf/2021-connection-point-forecasting-methodology.pdf?la=en

7 A 50% probability of exceedance (POE50) forecast is expected statistically to be met or exceeded one year in two, and is 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 that 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 that could be expected nine years in 10. AEMO notes that by definition the observed demand outcomes will occasionally fall outside the forecast 10% to 90% POE range. One time out of ten, the outcome is likely to be under and another one time out of 10, the outcome is likely to be above the range.

8 All time references in this document reflect Territory local time and the outcomes for the half-hour ending at the specified time.

Figure 3: Historical and forecast maximum system demand in the Darwin-Katherine by season year (year ending 31 August) 2016-17 to 2031-32



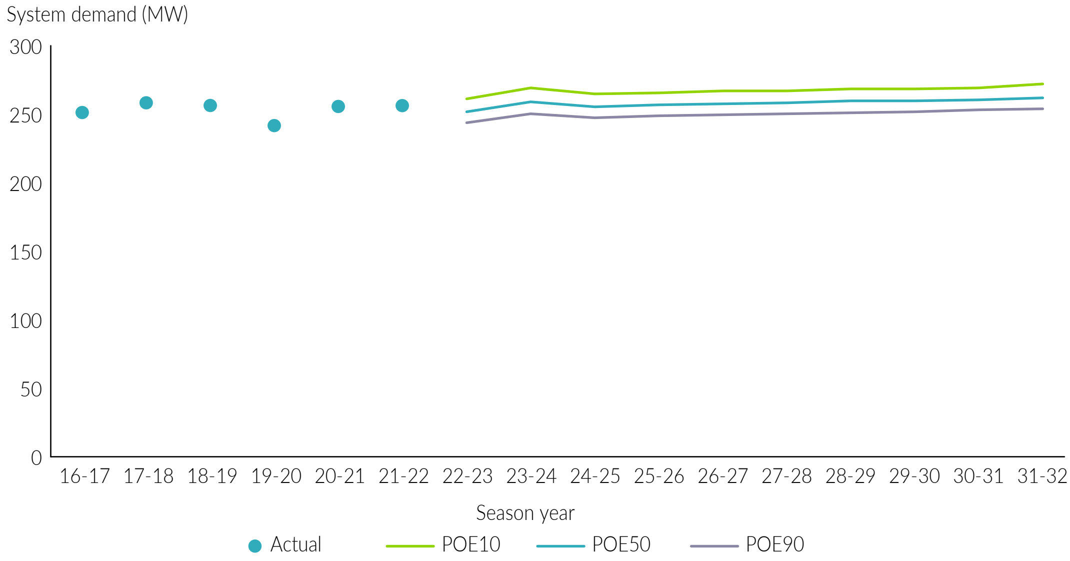
Darwin forecast

Figure 4 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Darwin node from 2016-17 to 2031-32.

The 2021-22 maximum system demand of 255.6 MW occurred during the wet season and was 0.2 MW higher than the previous year. Maximum system demand has historically occurred in the wet season in the mid-afternoon, driven by loads associated with air conditioning.

Maximum system demand is forecast to increase over the outlook period, with growth in the short term being attributed to forecast block load connections. The time of maximum system demand is trending later in the day due to the increasing penetration of distributed PV, with the 2021-22 maximum system demand occurring at 19:00. Maximum system demand is forecast to remain in the wet season and to occur between 18:00 and 19:30 over the outlook period.

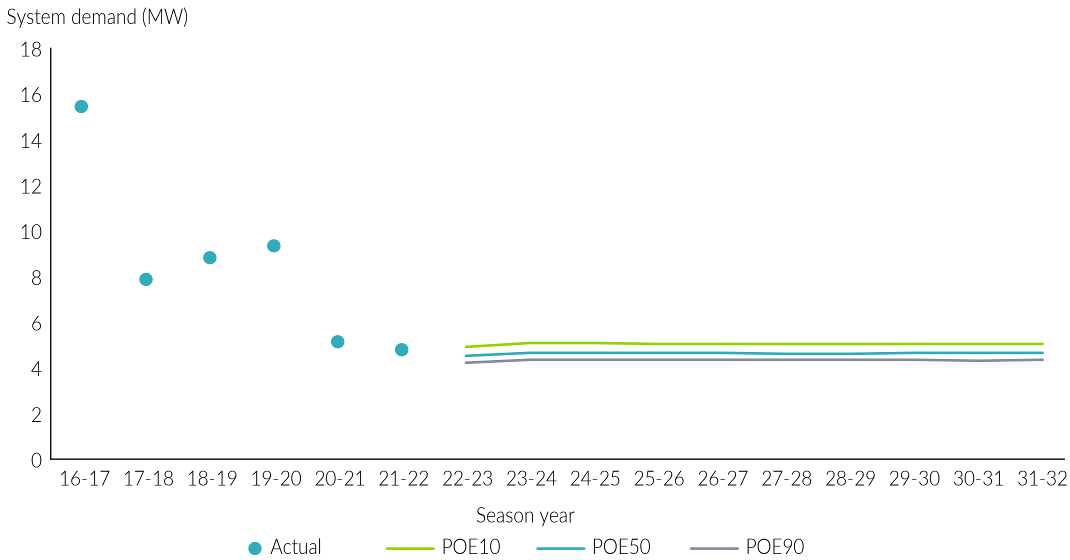
Figure 4: Historical and forecast maximum system demand in the Darwin node by season years (year ending 31 August), 2016-17 to 2031-32



Manton, Batchelor and Pine Creek forecast

Figure 5 shows annual historical and forecast maximum demand per season year (year ending 31 August) at different POE levels in the Manton, Batchelor and Pine Creek node from 2016-17 to 2031-32

Figure 5: Historical and forecast maximum system demand in the Manton, Batchelor and Pine Creek node, by season year (year ending 31 August), 2016-17 to 2031-32



Consistent with annual electricity consumption, maximum system demand has historically been heavily influenced by industrial loads in the Manton, Batchelor and Pine Creek node. The large drop in system demand between 2016-17 and 2020-21 is attributed to numerous mine closures. The 2021-22 maximum system demand of 4.8 MW occurred during the shoulder season at 16:30 and was 0.35 MW lower than the previous year.

Maximum system demand is forecast to be flat over the outlook period due to forecast distributed PV installed capacity nearing full saturation. Although small in terms of absolute growth, the forecast increase in distributed PV is expected to push the forecast time of maximum system demand later into the evening. Once the timing has been pushed closer to sunset, the effects of additional distributed PV on maximum system demand is negligible. Maximum system demand is forecast to continue occurring in the shoulder season between 17:30 and 20:00 over the outlook period.

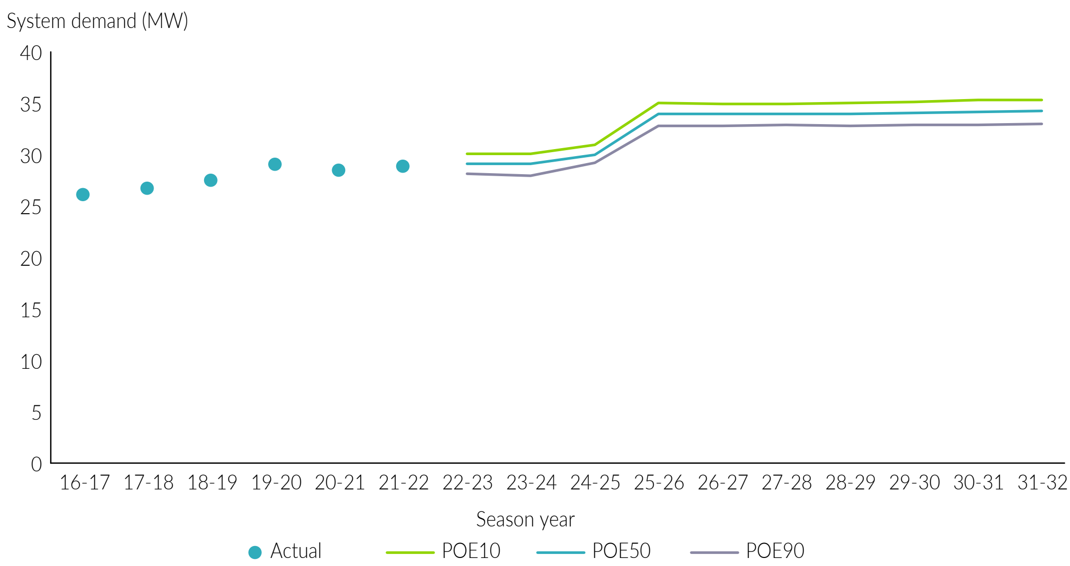
Katherine forecast

Figure 6 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Katherine node from 2016-17 to 2031-32.

The 2021-22 maximum system demand of 28.8 MW occurred during the final weeks of the shoulder season (October) before the wet season and was 0.3 MW lower than the previous year. Maximum system demand has historically occurred in the final weeks of the shoulder season or during the wet season in the mid-afternoon, driven by loads associated with air conditioning.

Consistent with the annual electricity consumption forecast, maximum system demand is forecast to increase over the outlook period from 2024-25 onwards. The forecast growth is attributed to expected block load connections. By 2028, maximum system demand is forecast to occur between 17:00 and 18:30, when increases in distributed PV installed capacity will have negligible impact.

Figure 6: Historical and forecast maximum system demand in the Katherine node by season year (year ending 31 August), 2016-17 to 2031-32



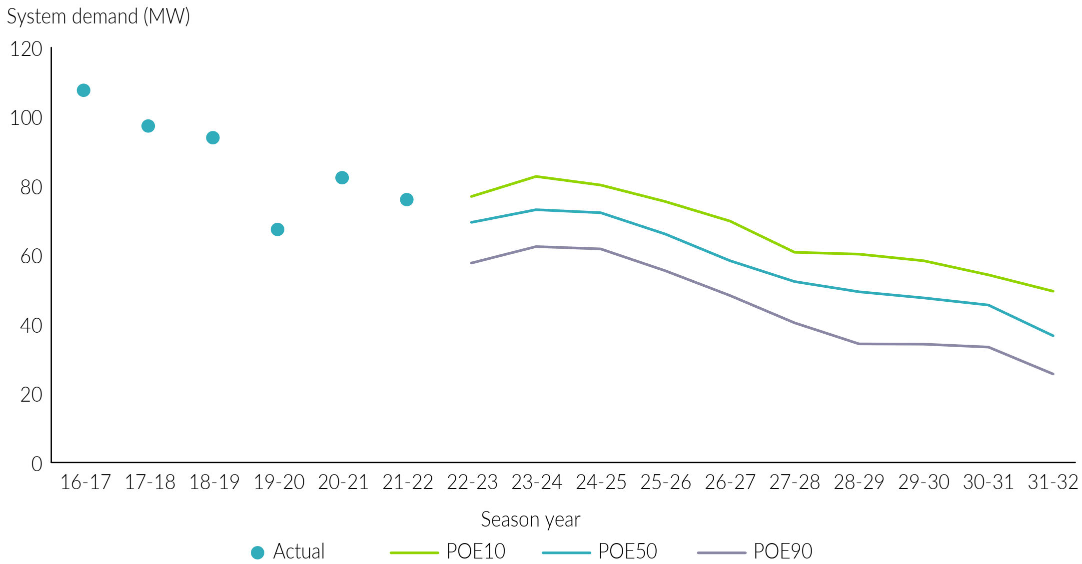
Minimum demand

Minimum system demand forecasts for the aggregated Darwin-Katherine power system and for each of its nodes have been produced independently. The three nodal forecasts are “non-coincident” because their minimum demands do not necessarily coincide with the time of Darwin-Katherine’s aggregated minimum system demand. To ensure consistency across the forecasts, these non-coincident nodal forecasts have been reconciled against the aggregated Darwin-Katherine forecast and are presented as so. The reconciliation approach used can be found in AEMO’s connection point forecasting methodology.[9]

Darwin-Katherine forecast

Figure 7 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Darwin-Katherine power system from 2016-17 to 2031-32.

Figure 7: Historical and forecast minimum system demand in Darwin-Katherine by season year (year ending 31 August), 2016-17 to 2031-32



Minimum system demand has historically occurred in the dry season in the early morning. The 2021-22 minimum system demand occurred during the middle of the day in the dry season at 76.1 MW, which was 6.4 MW lower than the previous year. This shift to the middle of the day is driven by the growth in installed distributed PV capacity. The growth in installed distributed PV capacity is also forecast to decrease minimum system demand over the outlook period.

Overall, the minimum system demand is forecast to continue occurring in the dry season and between 12:30 and 14:00. As minimum demand continues to decline, managing power system security within the Darwin-Katherine power system may become increasingly challenging. Minimum system demand implications are discussed later in this chapter.

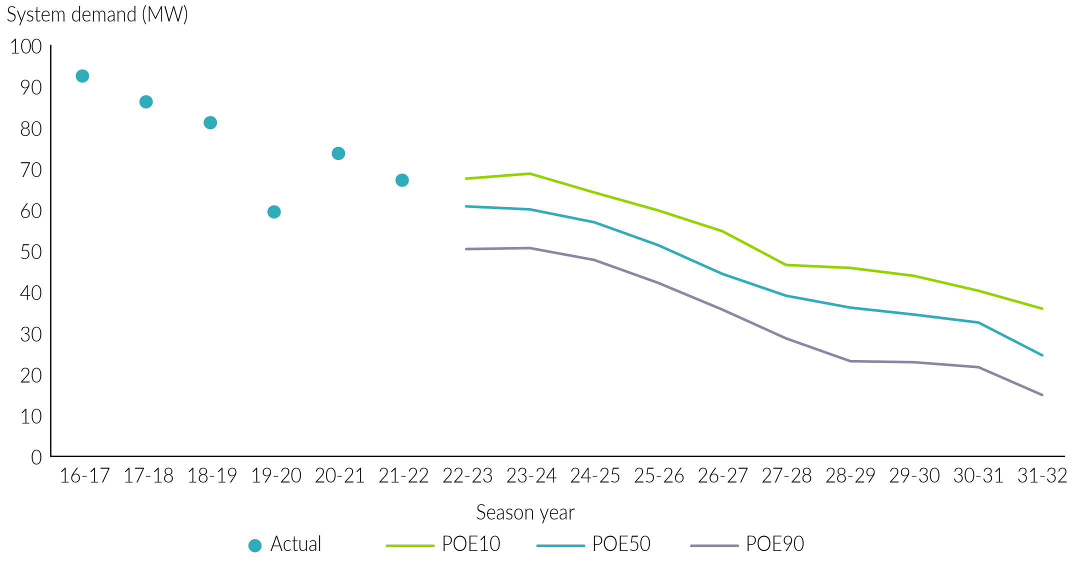
9 AEMO’s connection point forecasting methodology can be found here: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/tcpf/2021-connection-point-forecasting-methodology.pdf

Darwin forecast

Figure 8 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Darwin node from 2016-17 to 2031-32.

Similar to Darwin-Katherine, the minimum system demand in the Darwin region has historically occurred during the dry season in the early morning. However, there has been a continued trend of midday minimums in this region, due to the increasing penetration of distributed PV. In 2021-22, minimum system demand occurred during the middle of the day at 67.4 MW, which was 5.8 MW lower than the previous year. Minimum system demand is forecast to continue occurring in the dry season between 12:30 and 14:00 over the outlook period.

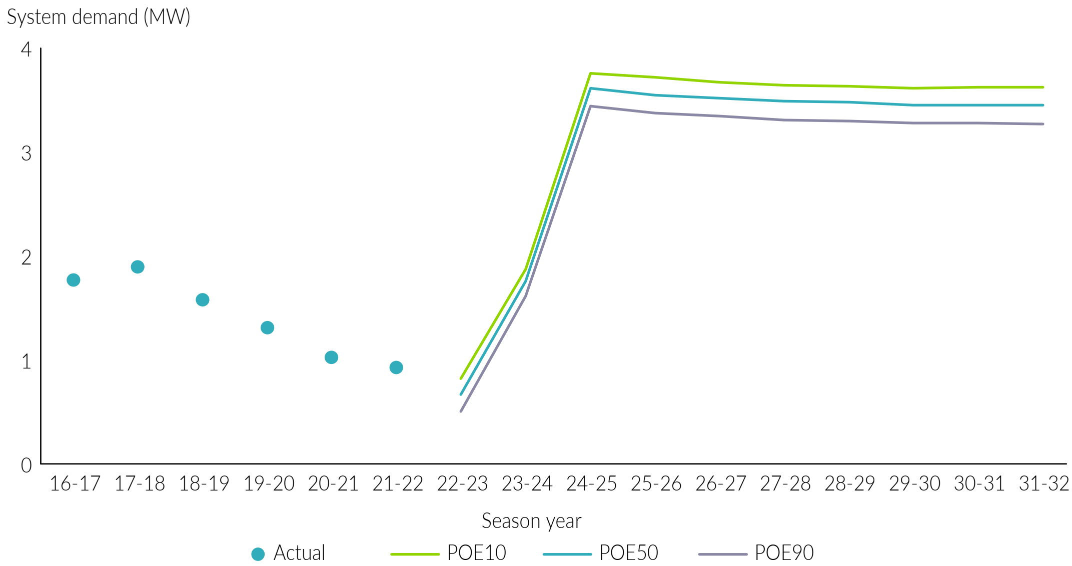
Figure 8: Historical and forecast minimum system demand in the Darwin node by season year (year ending 31 August), 2016-17 to 2031-32



Manton, Batchelor and Pine Creek forecast

Figure 9 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Manton, Batchelor and Pine Creek node from 2016-17 to 2031-32.

Figure 9: Historical and forecast minimum system demand in the Manton, Batchelor and Pine Creek node by season year (year ending 31 August), 2016-17 to 2031-32



Minimum system demand has historically been heavily influenced by industrial loads in the region, with minimum system demand coinciding with industrial outages at either Union Reef or Cosmo mines (these mines are now closed) and occurred in either the dry or wet seasons (see Section A1.7.2 for season definitions). The 2021-22 minimum system demand of 0.93 MW occurred during the dry season at 12:00 and was unaffected by any industrial load outages.

Minimum system demand is forecast to increase in the short term due to expected future block load connections and then remain relatively flat over the remaining outlook period due to forecast distributed PV installed capacity nearing full saturation. The minimum system demand is forecast to shift to the wet season and occur towards the late morning to midday between 10:00 and 14:00 over the outlook period driven by the forecast increase in distributed PV. While it is statistically the most likely outcome that minimum system demand will occur during the wet season over the outlook period, coinciding with weekends or public holidays with high distributed PV output and mild weather, minimum system demand may also occur in the dry season in some years.

Katherine forecast

Figure 10 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Katherine node from 2016-17 to 2031-32.

Figure 10: Historical and forecast minimum system demand in the Katherine node by season year (year ending 31 August), 2016-17 to 2031-32

Minimum system demand has historically occurred in the early morning during the shoulder season. However, in recent years, the timing and season of minimum system demand has deviated from this. For instance, it occurred in early morning in the dry season in 2018-19 and in the middle of the day during the shoulder season in 2019-20. In 2020-21, minimum system demand occurred overnight during the shoulder season, and in 2021-22, the minimum demand of 6.71 MW shifted to mid-morning at 09:30 in the shoulder season.

Minimum system demand is forecast to increase in the short term due to expected block load connections, followed by a gradual decrease due to increasing distributed PV penetration. Due to the growth in distributed PV, minimum system demand is forecast to shift to the dry season and to occur in the middle of the day between 12:00 and 14:00 over the outlook period.

System and underlying daily load profile

Figure 11, Figure 12, and Figure 13 show typical daily load profiles under maximum and minimum demand conditions in the: Darwin; Manton, Batchelor and Pine Creek; and Katherine nodes in 2021-22, respectively.

The maximum demand profile represents the average of the 10 highest demand values in the season in which the annual maximum occurred for each node. In 2021-22, the annual maximum occurred in the wet season in the Darwin node, and in the shoulder season in the Manton, Batchelor and Pine Creek, and Katherine nodes. The minimum demand profile represents the average of the 10 lowest demand values in the season in which the annual minimum occurred for each node. The annual minimum occurred in the dry season in the Darwin and Manton, Batchelor and Pine Creek nodes, and in the shoulder season in the Katherine node. The blue and green lines represent the maximum underlying demand and system demand respectively. The dark purple and light purple lines represent the minimum underlying demand and system demand respectively.

'System demand' includes output from all large-scale generation. In contrast, 'underlying demand' is an estimate of all the power used by consumers from the power point, from any source (including both the network and distributed PV installed by residential or commercial consumers).

In all nodes, distributed PV generation during the day has lowered maximum and minimum system demand, leading to the timing of maximum system demand to later in the day relative to the underlying demand.

For the Darwin and Manton, Batchelor and Pine Creek nodes, the amount of distributed PV installed has shifted the minimum to a midday minimum from a minimum demand which occurred overnight.

For Katherine, the absolute minimum has shifted to mid-morning from a minimum demand which occurred overnight in 2021-22. However, the average of the 10 lowest demand values in the season shows that minimum demand typically occurs early morning, as shown in Figure 13.

In all nodes, the impact from distributed PV during the day is similar for both seasons although it is slightly greater during the dry season in the Darwin node.

Figure 11: Daily load profiles for the Darwin node, wet and dry seasons, 2021-22

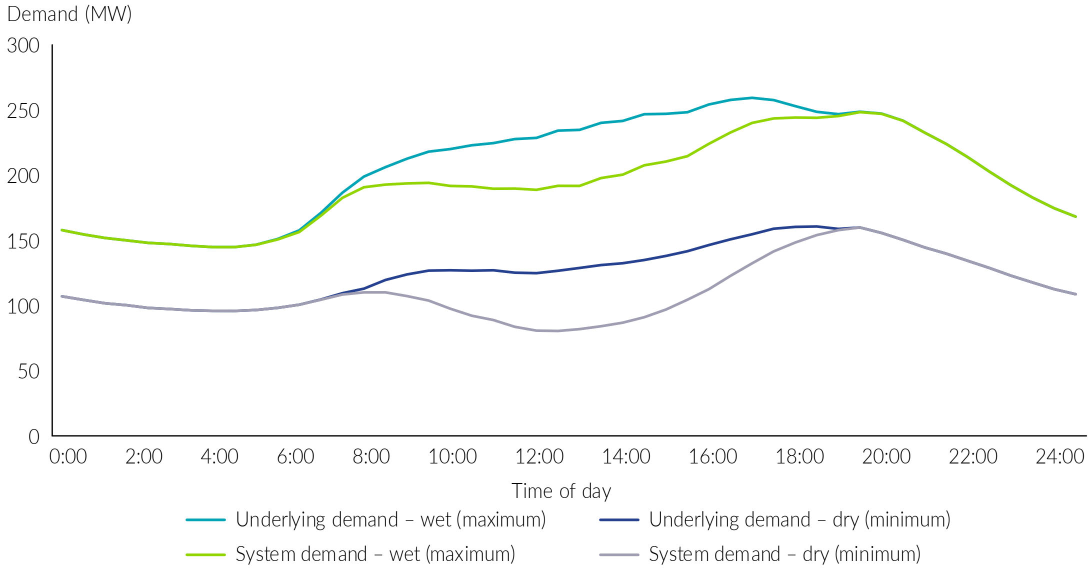


Figure 12: Daily load profiles for the Manton, Batchelor and Pine Creek node, shoulder and dry season, 2021-22

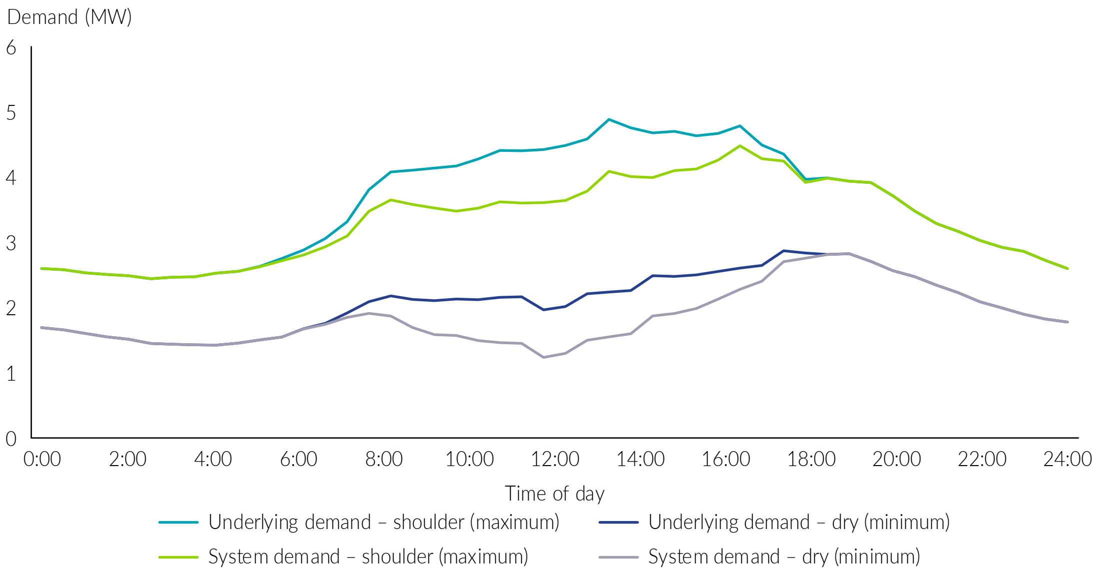
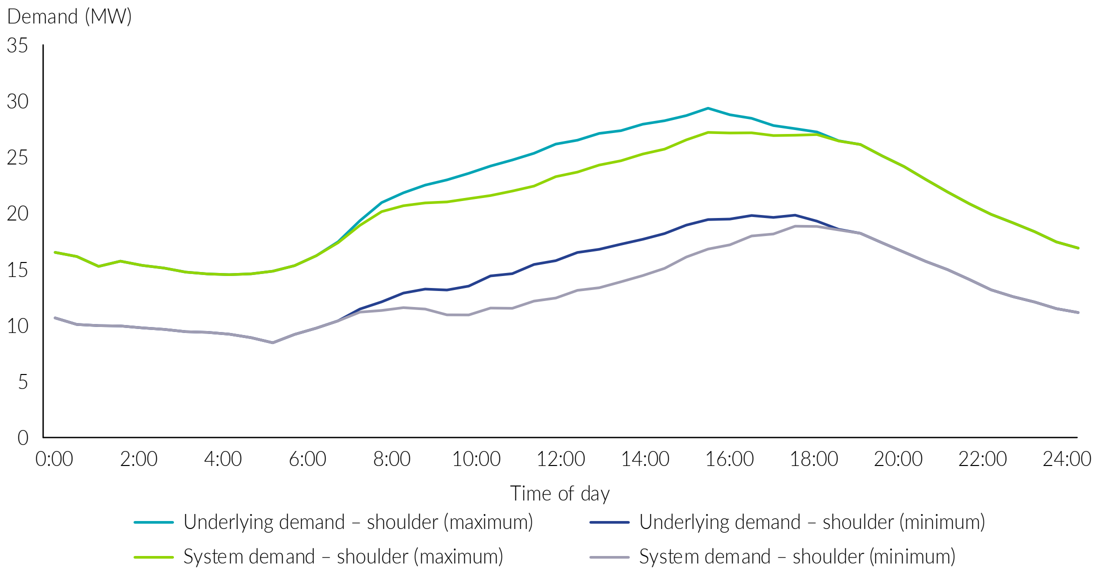


Figure 13: Daily load profiles for the Katherine node, shoulder seasons, 2021-22



Supply adequacy outlook

This section details the results for unserved energy outcomes for the Darwin-Katherine power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Darwin-Katherine power system.

Unserved energy outcomes

Expected USE in the Darwin–Katherine power system is forecast to be below the adopted 0.002% reliability standard in the initial years of the outlook. In 2024-25, total dispatchable capacity is expected to increase in Darwin-Katherine due to CIPS unit 10 becoming operational.[10] Expected new generation in the Darwin–Katherine power system is forecast to improve system reliability in the region in the initial years of the outlook period. For more details on assumed committed generation, see Table 5 in Section A1.8.3.

Figure 14 shows annual results with the last five years of the outlook shown separately on a larger axis due to the magnitude of forecast USE. In 2027-28 expected USE is forecast to increase substantially, exceeding the 0.002% reliability standard for the remainder of the outlook period, and reaching more than 0.6% in the final years of the outlook period. This is due to the expected retirement of a number of generating units at the CIPS. For more details on assumed retirement dates, see Table 4 in Section A1.8.2.

Despite the retirement of units at the KPS being 'pushed' to outside the outlook period in the 2022 NTEOR compared with the 2021 NTEOR, the forecasts still indicate that additional generation, demand side participation and or storage solutions are required to offset the impact of generation retirements at the CIPS and maintain the current level of reliability. Detailed USE forecast is shown in Appendix A2.2.

10 The scheduled CIPS-10 start date is 31 December 2024. Its effect on USE is only fully observed in 2025-26 and subsequent years.

Figure 14: Forecast reliability, Darwin–Katherine system, 2023-24 to 2031-32

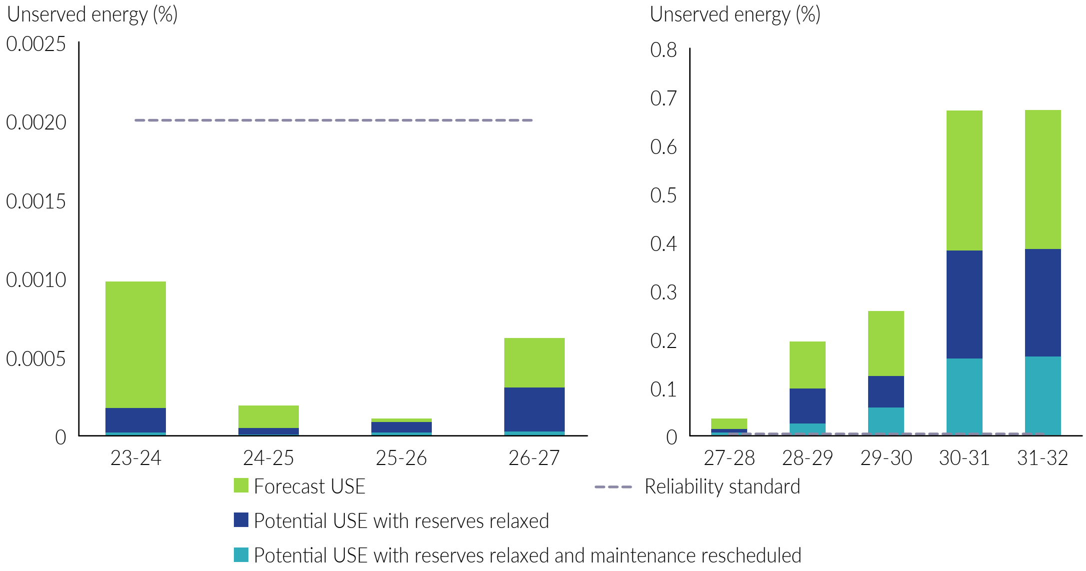


Figure 14 also shows forecasts using alternative modelled sensitivities, which project that consumer reliability outcomes could be improved where reserve requirements and or generator maintenance are able to be relaxed or rescheduled. These sensitivities show the potential for improving short-term reliability for consumers, but result in additional risks to system security and generation assets. Overall, the analysis suggests there is sufficient capacity to ensure reliability remains within the adopted reliability standard until 2027-28.

However, the nodes within the Darwin–Katherine power system are forecast to have different reliability risks due to the impact of transmission limitations.[11] While the Darwin and Katherine nodes show results consistent with the overall power system trend, the Manton, Batchelor and Pine Creek node shows significantly lower risks than the overall power system. This suggests that further location-specific solutions may be required.

11 The three nodes are connected by a 132 kilovolt (kV) transmission line that is subject to numerous thermal and system security limitations.

Figure 15: Forecast reliability, Darwin node, 2023-24 to 2031-32

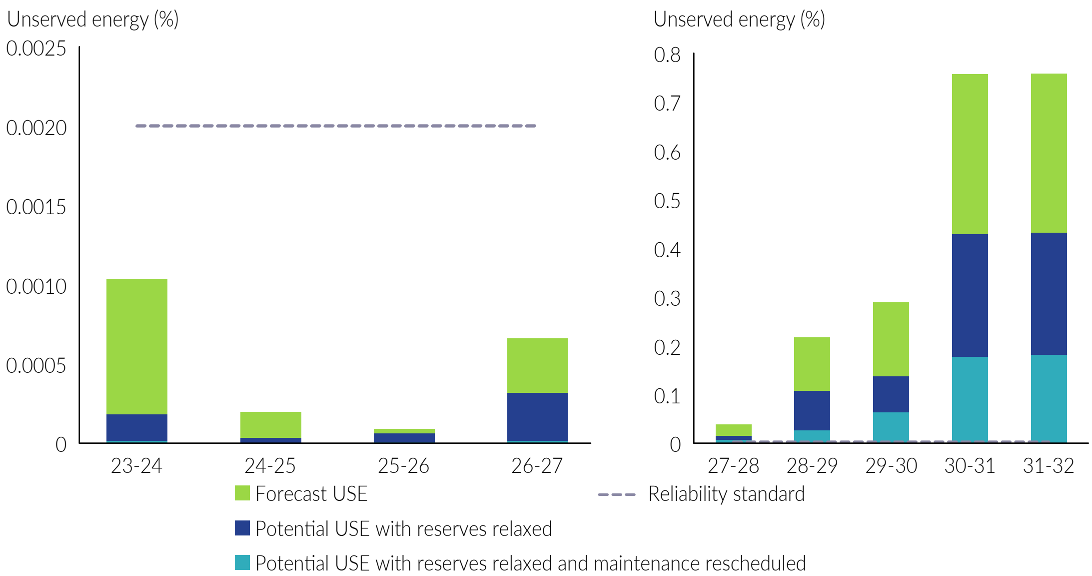


Figure 15 shows expected USE in the Darwin node. Expected USE in the Darwin node is forecast to be below the 0.002% reliability standard in the initial years of the outlook period. Expected new generation in the Darwin-Katherine power system acts to improve system reliability in the Darwin region, most notably Territory Generation's CIPS-10 unit. Further, Territory Generation's Darwin BESS is expected to indirectly improve supply availability through its contribution to system security requirements. For more details on assumed committed generation in the Darwin-Katherine power system, see Table 5 in Section A1.8.3.

The Darwin node is forecast to exceed the USE reliability standard from 2027-28 onwards. This is due to the expected retirement of a number of generating units at the CIPS. For more information on retirements, see Table 4 in Section A1.8.2. The forecast for the Darwin node indicates that additional generation and or storage solutions will be required to offset the impact of generation retirements. A table of USE forecast in the Darwin region is shown in Appendix A2.2.

Figure 16 and Figure 17 show expected USE for the two nodes south of Darwin. The smaller node of Manton, Batchelor and Pine Creek shows low levels of USE until 2030-31, when risks in the overall power system increase. The Katherine node exceeds the USE reliability standard in the outlook from 2027-28 onwards and shows a similar trend to the overall power system. This is due to tightness of expected available dispatchable capacity and maximum system demand.

Figure 16: Forecast reliability, Manton, Batchelor and Pine Creek node, 2023-24 to 2031-32

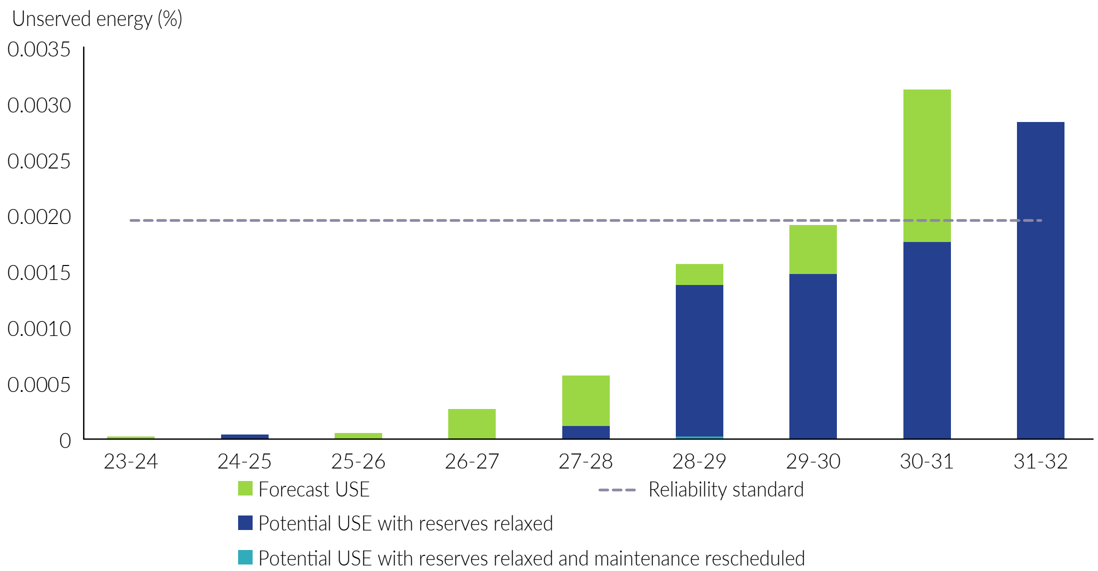
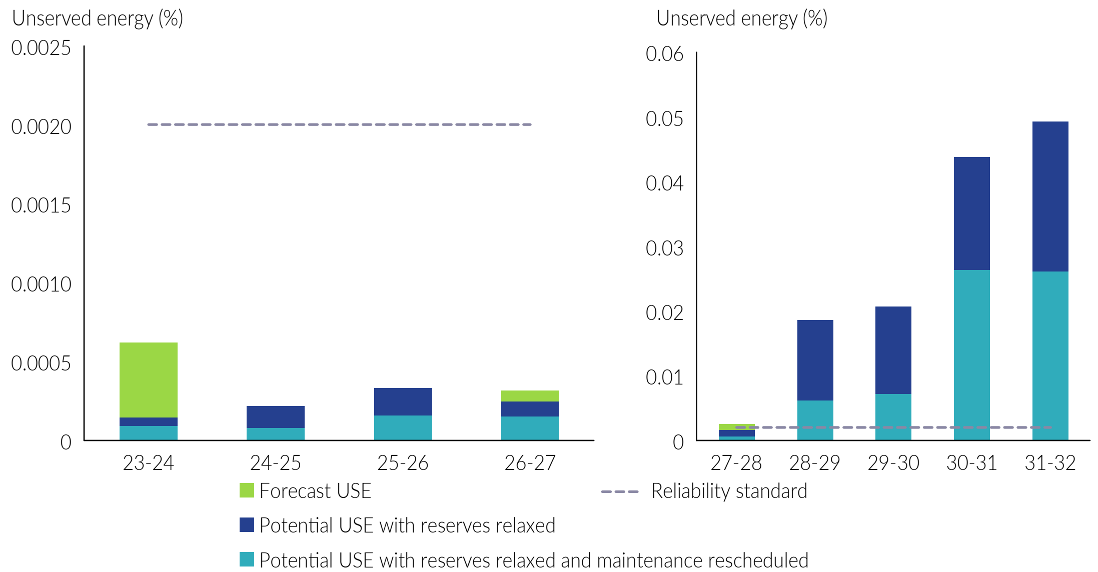


Figure 17: Forecast reliability, Katherine node, 2023-24 to 2031-32

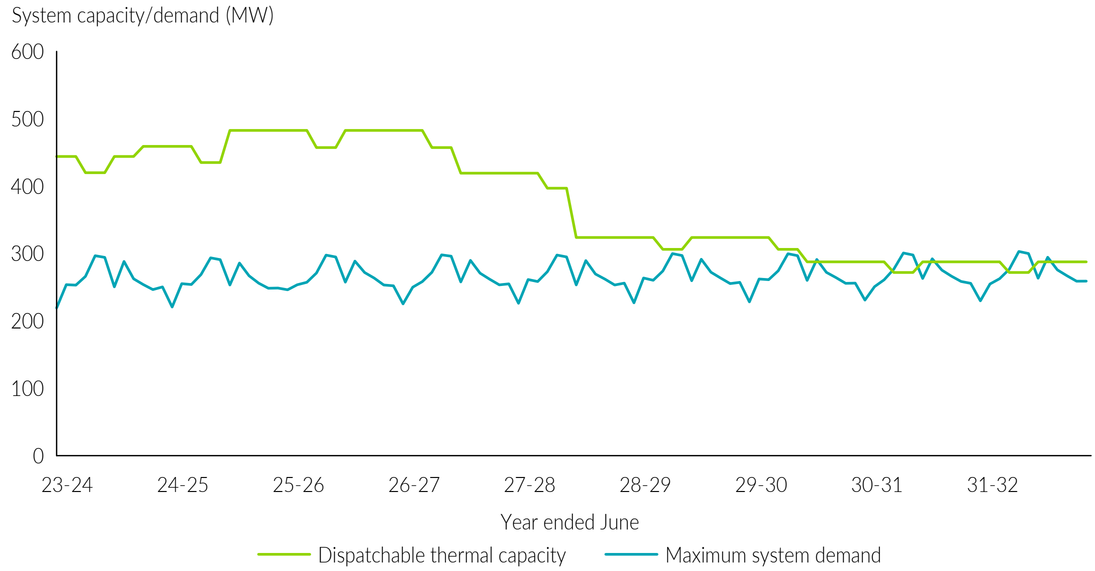


Reserve capacity

The increase in expected USE in the Darwin–Katherine power system is driven by a lack of capacity after the planned retirement of units at the CIPS from 2026-27.

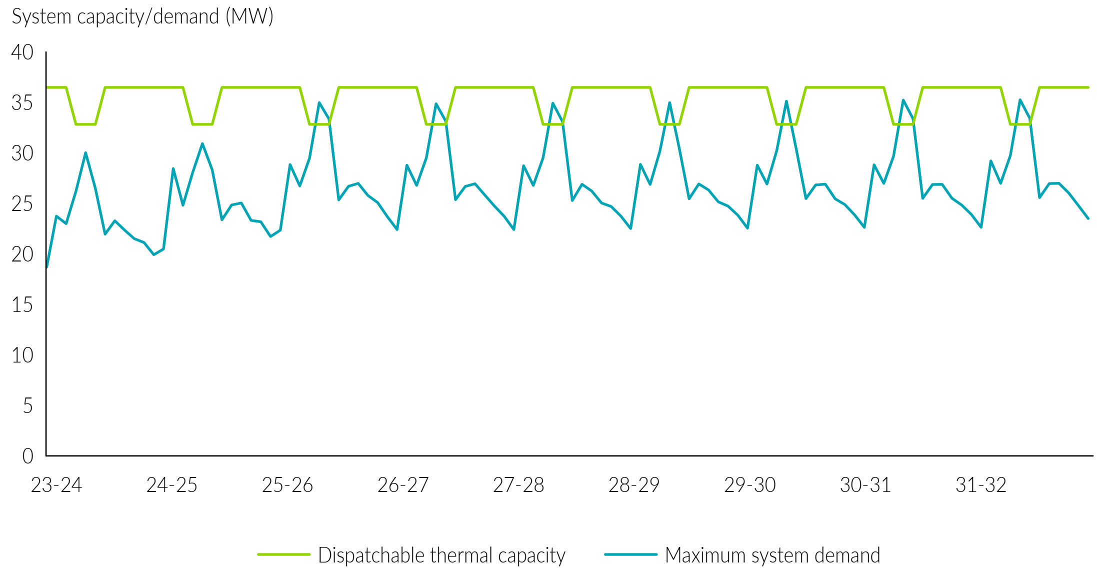
Figure 18 shows the seasonal dispatchable capacity against forecast monthly maximum system demand in the Darwin–Katherine power system. Figure 18 does not account for the contribution from sources that are not fully dispatchable, such as the large-scale solar power stations discussed in Section A1.8.3.

Figure 18: Forecast seasonal dispatchable capacity and monthly maximum system demand (POE10), Darwin-Katherine power system, 2023-24 to 2031-32



Katherine has tight reserve capacity from the early years of the outlook period, as shown in Figure 19. While the reliability risk in the region remains high, the forecast shortfall is substantially lower than the forecast in the previous year due to the retirement of units at the KPS being 'pushed' to outside of the outlook period.

Figure 19: Forecast seasonal dispatchable capacity and monthly maximum subregional demand (POE10), Katherine node, 2023-24 to 2031-32



Minimum system demand implications

Minimum system demand is forecast to decline rapidly in the Darwin–Katherine power system, due to increasing penetration of distributed PV. By the end of the outlook period (30 June 2032), minimum system demand is forecast to be less than 40 MW, which will likely cause system security implications without further measures such as load shifting capability and or emergency controls.

Similar trends are evident in the NEM, where declining minimum demand raises issues with managing voltage, system strength, and inertia and is creating near-term operational and planning challenges for sustaining a reliable and secure power system. AEMO is working with NEM stakeholders to implement new capabilities that will assist in mitigating these risks, including:

- effective market and regulatory arrangements that incentivise more demand during the middle of the day
- innovative solutions that could include providers or aggregators of distributed energy resources (DER) offering services such as increased PV system controllability, load flexibility and storage
- ensuring all new distributed PV installations have suitable disturbance ride-through capabilities and emergency shedding capabilities to be enabled under rare circumstances as a last resort to maintain system security.

For more information on risks at time of minimum system demand in the NEM, which are equally relevant to the Territory, and mitigation strategies, see AEMO's 2022 NEM *Electricity Statement of Opportunities* (ESOO),[12] 2022 *System Strength Report*[13] and 2022 *Inertia Report*.[14]

12 See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en

13 See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en

14 See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-inertia-report.pdf?la=en

Plans that may help mitigate identified reliability risks

Generation adequacy assessments included in this outlook consider only existing and committed developments, where developments must be relatively well advanced to be considered committed. These assessments intentionally exclude other developments not yet considered committed to highlight the scale of the investment required and to encourage the commitment of further solutions, whether they are related to generation, transmission, DER or demand side participation.

During consultation with industry participants, the Commission were made aware of other plans that propose to directly increase generation capacity in the Darwin-Katherine power system and that may substantially reduce reliability risks if progressed. These plans include:

- the Darwin–Katherine Electricity System Plan.[15] The plan involves the development of a new renewable energy hub, as well as increased levels of distributed PV and battery energy storage systems. The 2023-24 Territory Budget allocated funding for the Darwin-Katherine Electricity System Plan, including $12 million to undertake planning and head works to develop the renewable energy hub. Should the developments from this plan continue to progress, the reliability outlook could improve considerably.
- Territory Generation's draft fleet transition plan business case (unpublished). This plan includes a proposal to, among other things, replace retiring capacity with new gas-fired generators and battery energy storage systems to replace capacity, energy and essential system services. Territory Generation's plan is not approved beyond the short term according to its 2023-24 statement of corporate intent. However, such a proposal has the potential to improve the outlook considerably.

As it is outside the scope of the this report, the Commission and AEMO have not given detailed consideration to these plans and make no comment as to whether they are or are not the best solutions to address the forecast reliability issues over the outlook period.

The Commission has also been made aware of other Territory Government-supported activities which may indirectly lead to or facilitate more generation capacity, and may reduce reliability risks, such as allocation of funding to progress electricity market reforms in the 2023-24 Territory Budget and establishment of an Electricity Market Reform Implementation Taskforce to deliver on Government's reform agenda, which includes:

- a review of power system security risks for the Darwin-Katherine electricity system
- preparing a coordinated plan to integrate renewables over the 2023-24 to 2025-26 period
- initiating development of an integrated system plan with a 10-year outlook.

15 See https://territoryrenewableenergy.nt.gov.au/__data/assets/pdf_file/0011/1056782/darwin-katherine-electricity-system-plan-web.pdf.

2 Alice Springs outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Alice Springs power system over the outlook period to 30 June 2032.

Annual electricity consumption

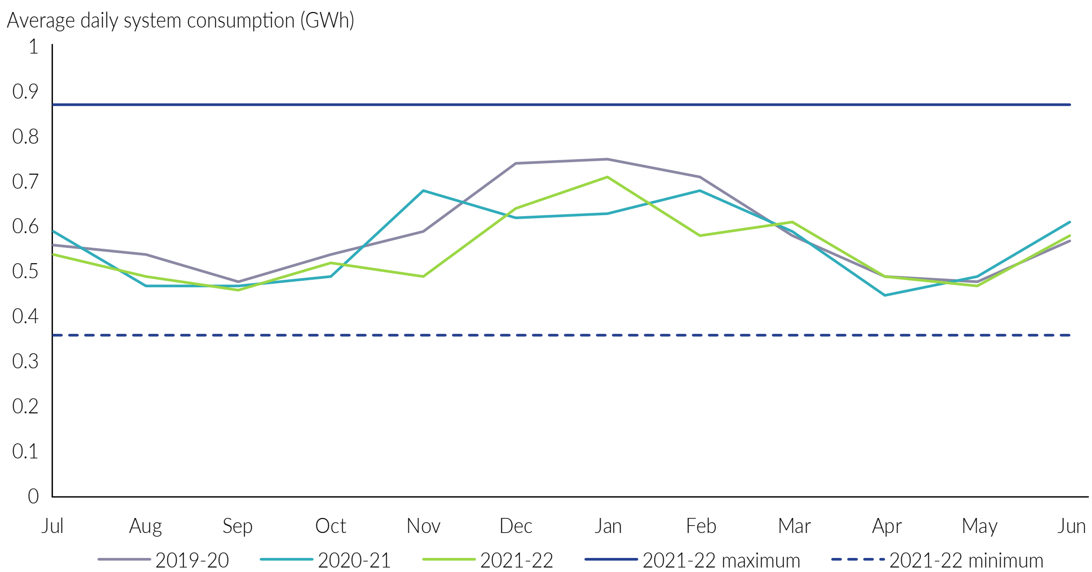
The following section includes recent trends in annual electricity consumption in the Alice Springs power system, along with forecasts over the outlook period.

Electricity consumption observed in 2021-22

In 2021-22, total annual system consumption in the Alice Springs power system was 197 GWh. This was 2.6% lower than system consumption in 2020-21. This reduction can be attributed in part to the continued growth of distributed PV. The installed capacity of distributed PV increased from 3.75 MW to 4.20 MW over 2021-22.

Figure 20 shows average daily system consumption, by month, in the Alice Springs power system between 2019-20 and 2021-22. Average daily system consumption in 2021-22 was 0.54 GWh, and the daily maximum and daily minimum system consumption were 0.86 GWh and 0.35 GWh, respectively. The month-to-month variability in system consumption indicates that Alice Springs has relatively strong seasonable variability.

Figure 20: Average daily system consumption for Alice Springs by month, 2019-20 to 2021-22

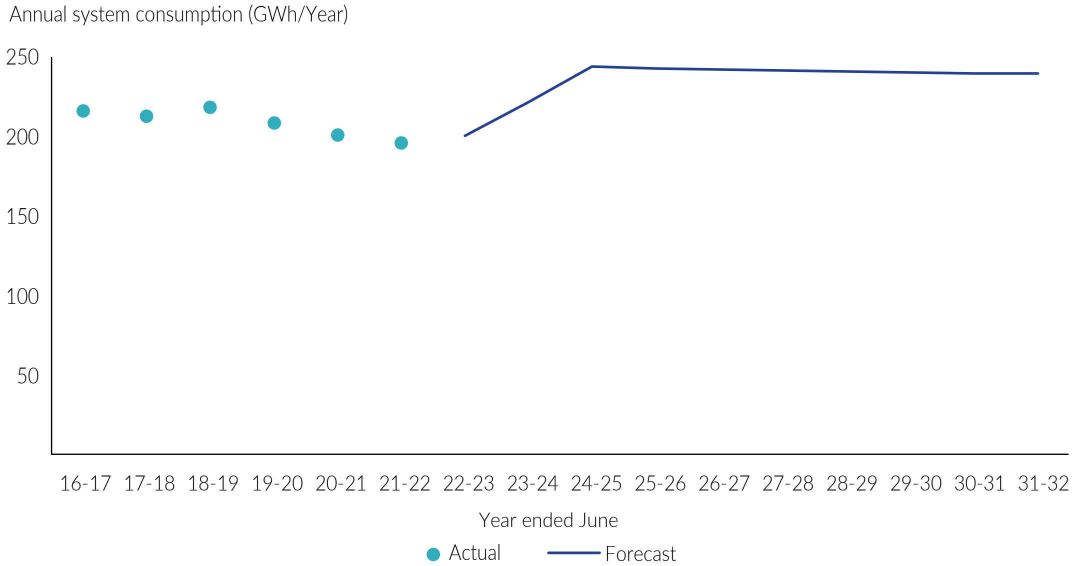


Recent history and forecast

Figure 21 shows historical and forecast annual system consumption in the Alice Springs power system from 2016-17 to 2031-32. The historical values of annual system consumption show a general decline in recent years. This trend is largely driven by increases in distributed PV.

Forecast annual system consumption is expected to increase in 2023-24 and 2024-25 due to a large load at the Joint Defence Facility Pine Gap (JDFPG) connecting midway through 2023-24. Annual system consumption is forecast to decline after 2024-25 due to forecast growth in distributed PV.

Figure 21: Historical and forecast annual system consumption for Alice Springs by financial year, 2016-17 to 2031-32



Maximum demand

Figure 22 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2016-17 to 2031-32.

Figure 22: Historical and forecast maximum system demand for Alice Springs by season years (year ending 31 August), 2016-17 to 2031-32

Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with cooling. In 2021-22, maximum system demand of 48.6 MW occurred in the summer season at 16:30.

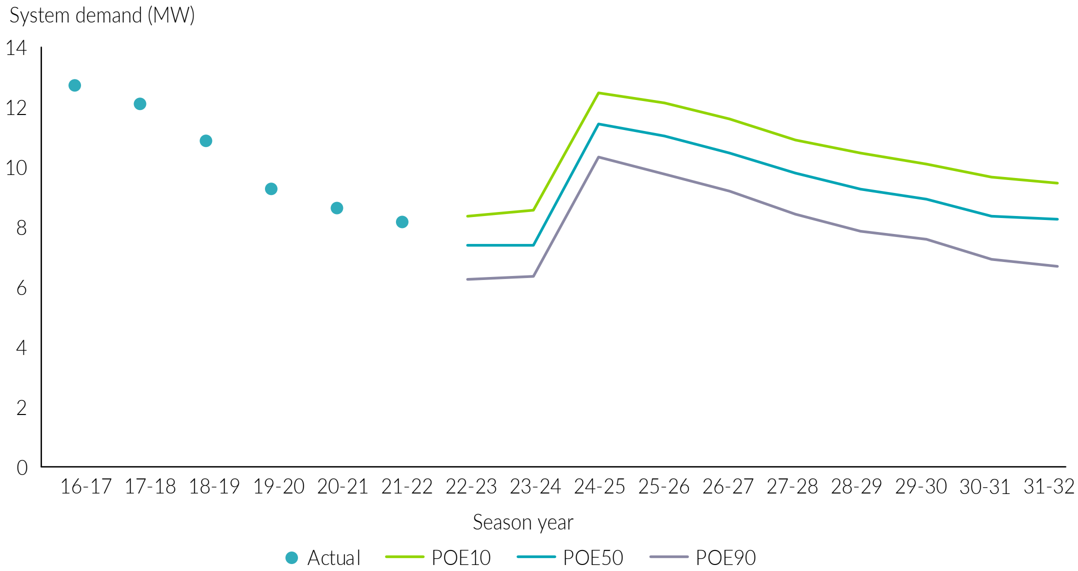
Maximum system demand is forecast to increase in 2023-24, with most of this growth attributed to new load at the JDFPG. Maximum system demand is then forecast to remain relatively flat over the rest of the outlook period. The forecast increase in distributed PV installed capacity will push the time of maximum demand later in the day. Once maximum system demand has been pushed beyond sunset there will be no further impact of distributed PV growth on maximum system demand. The maximum system demand is forecast to occur between 17:00 and 19:00 over the outlook period and to remain in the summer season.

Minimum demand

Figure 23 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2016-17 to 2031-32. Minimum system demand historically occurred in the early morning, however between 2016-17 and 2020-21 it occurred in the middle of the day in the shoulder season. The 2021-22 minimum system demand of 8.2 MW occurred at 10:30 early in the summer season, in the month of November.

Minimum system demand is forecast to increase in 2023-24 and 2024-25 (due to the expected connection of new load at the JDFPG), before trending downwards for the remainder of the outlook period as distributed PV continues to grow. The minimum system demand is forecast to occur in the middle of the day, and the month in which the minimum occurs is expected to occur is September or October (the shoulder season).

Figure 23: Annual historical and forecast minimum system demand for Alice Springs, season years (year ending 31 August) 2016-17 to 2031-32

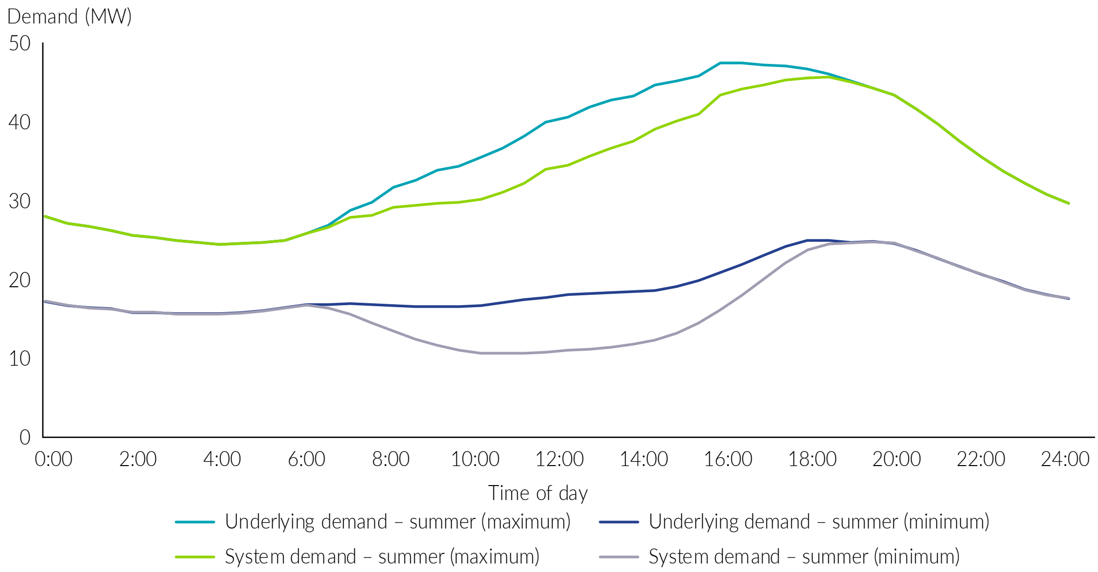


System and underlying daily load profile

Figure 24 shows typical daily load profiles under maximum and minimum demand conditions in the Alice Springs power system in 2021-22. Although both events occurred in the summer season, maximum demand occurred in January and minimum demand occurred in November. The maximum demand profile represents the average of the 10 highest demand values in the summer season, and the minimum demand profile represents the average of the 10 lowest demand values in the summer season. The blue and green lines represent the maximum underlying demand and system demand respectively. The dark purple and light purple lines represent the minimum underlying demand and system demand respectively.

The continued trend of midday minimums confirms there is sufficient distributed PV capacity installed in the power system to consistently shift the time of minimum system demand from early morning to the middle of the day, with the growth in distributed PV also moving the timing of maximum system demand, which has generally been moved to later in the day.

Figure 24: Daily load profile for Alice Springs, summer, 2021-22



Supply adequacy outlook

This section details the results for unserved energy outcomes in the Alice Springs power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Alice Springs power system.

Unserved energy outcomes

Figure 25 shows that expected USE in Alice Springs is forecast to be above the 0.002% adopted reliability standard across all years of the outlook period. Expected USE exceeds the reliability standard in the initial three years of the outlook due to the retirement of a unit at the RGPS and a high assumed forced outage rate for the newer units (units 5 to 14) at the OSPS in 2023-24. From 2026-27, high levels of USE are forecast due to the expected retirement of the remaining units at the RGPS. The detailed USE forecast is shown in Appendix A2.2.

The newer OSPS units have shown high levels of forced outages in their short operating history. To reflect the risks arising from such outage rates, for modelling purposes, these units are assumed to retain their recent outage rate of 21.7% for the first forecast year (2022-23), and then gradually reduce over three years to the 3.9% rate (in 2024-25) proposed by the licensee (for more information, see Table 7 in Section A1.8.6). These assumptions impact results in the first year of the forecast in particular; however, in the third year the assumed outage rate is still sufficient for expected USE to exceed the 0.002% reliability standard.

The model suggests that units at the RGPS, despite being at end of their operational life with low reliability, will still contribute as back-up generators and as reserve-providing units. Once the units are fully retired, expected USE increases from 0.008% in 2025-26 to 0.02% in 2026-27, well above the adopted 0.002% standard for reliability (see Section A1.8.2 for more details). Forecast USE remains high from 2027-28 until the end of the outlook period due to high levels of scheduled maintenance.

Figure 25: Forecast reliability, Alice Springs system, 2023-24 to 2031-32

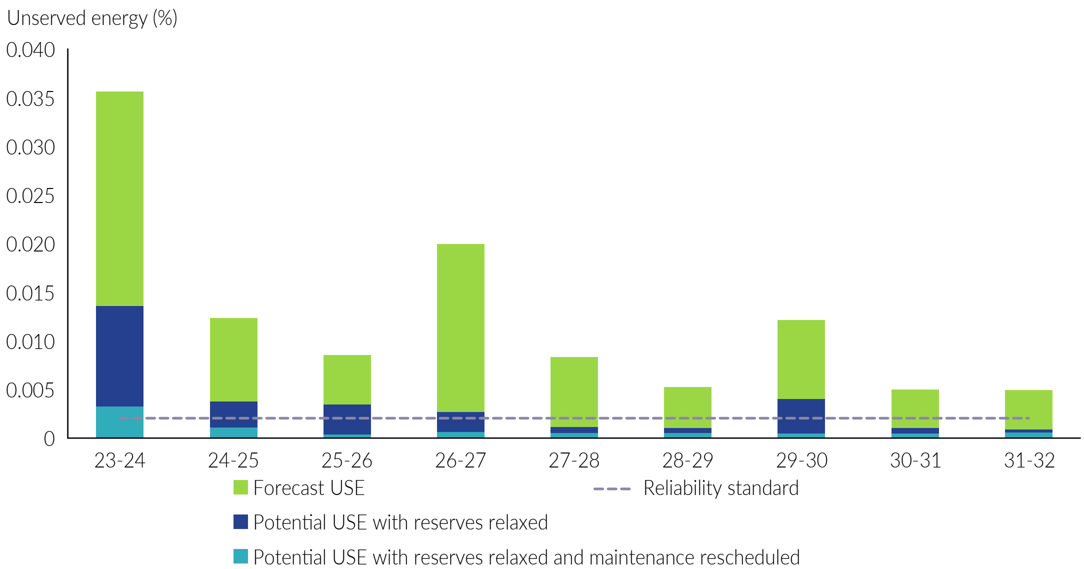
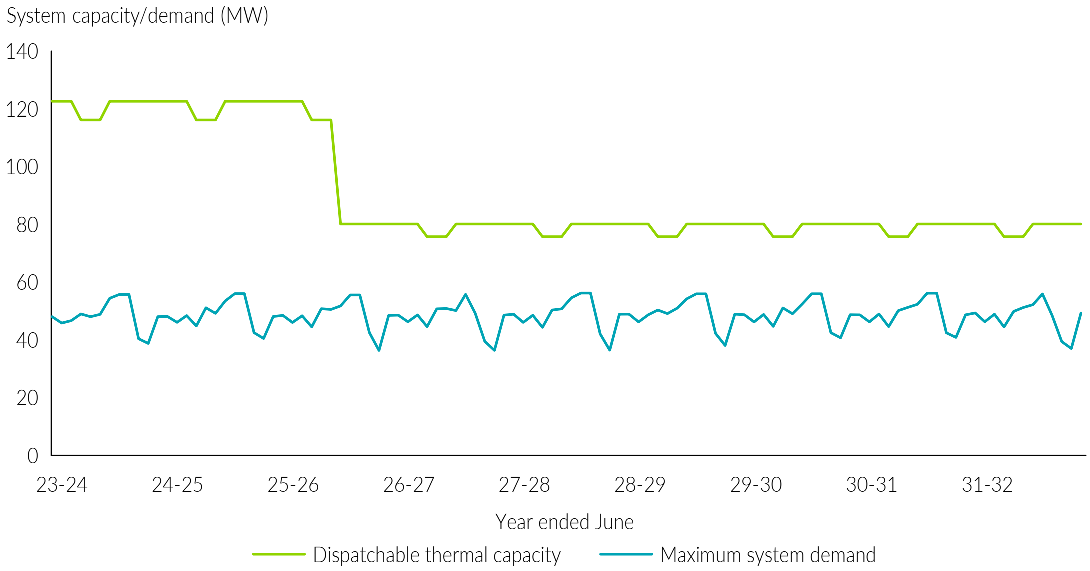


Figure 25 also shows forecasts using alternative modelled sensitivities, which indicate that consumer reliability outcomes could be improved where reserve requirements and or generator maintenance are able to be relaxed or rescheduled. These sensitivities show there is potential for improving short-term reliability for consumers, but this may result in additional risks to system security and generation assets. Overall, the analysis suggests that reliability and operability challenges persist over the outlook period.

Reserve capacity

Figure 26 shows how forecast surplus seasonal dispatchable capacity declines following the assumed retirement of the RGPS by the end of 2026. Figure 26 also shows a slight increase in forecast maximum system demand from 2023-24 after a sizeable block load is expected to connect to the network. Following this increase, peak demand is expected to remain stable until the end of the outlook period.

Figure 26: Forecast seasonal dispatchable capacity and monthly maximum demand (POE10), Alice Springs, 2023-24 to 2031-32



The high levels of forecast USE are a result of the reduced amount of generation capacity reserves and demonstrate the continued importance of coordinated outage planning at the OSPS and in the Alice Springs power system generally. Suboptimal planning of scheduled outages will make the power system more vulnerable to USE events in the case of unplanned outages.

3 | Tennant Creek outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Tennant Creek power system over the outlook period to 30 June 2023.

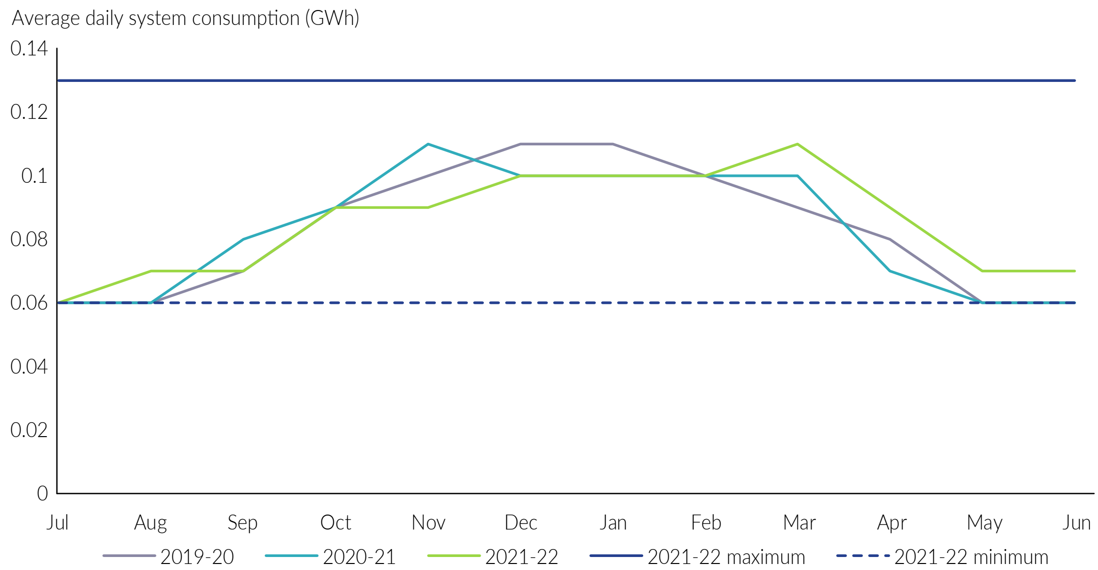
Annual electricity consumption

The following section includes recent trends in annual electricity consumption in the Tennant Creek power system, along with forecasts over the outlook period.

Electricity consumption observed in 2020-21

In 2021-22, total system consumption in the Tennant Creek power system was 30.8 GWh, which is a 3.2% increase from 2020-21. Figure 27 shows the average daily system consumption by month in the Tennant Creek power system between 2019-20 and 2021-22. Average daily system consumption in 2021-22 was 0.08 GWh, and maximum and minimum daily system consumption were 0.13 GWh and 0.06 GWh, respectively. The variability of consumption reflects the fact that Tennant Creek experiences wide temperature changes between seasons.

Figure 27: Average daily system consumption for Tennant Creek by month, 2019-20 to 2021-22

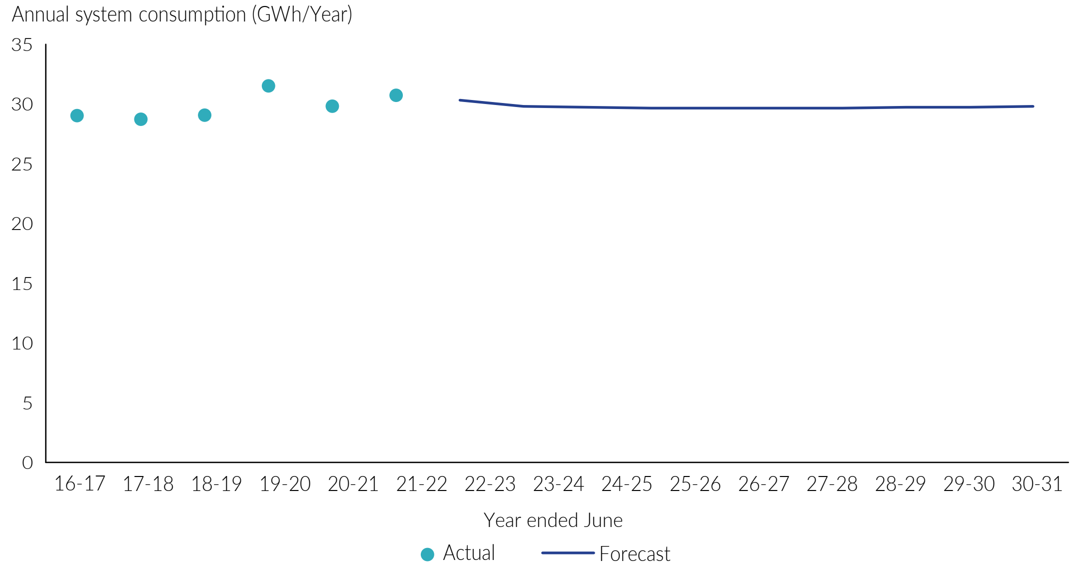


Recent history and forecast

Figure 28 shows historical and forecast annual system consumption in the Tennant Creek power system from 2016-17 to 2031-32. Historical system consumption observations have been relatively steady since 2016-17. The effect of distributed PV on annual system consumption has been relatively minor as a result of the low uptake of distributed PV installations in the region.

Annual system consumption is forecast to remain flat over the outlook period as changes in electricity consumption, due to population drivers and changes in installed PV capacity, are expected to be relatively minimal compared with other regions.

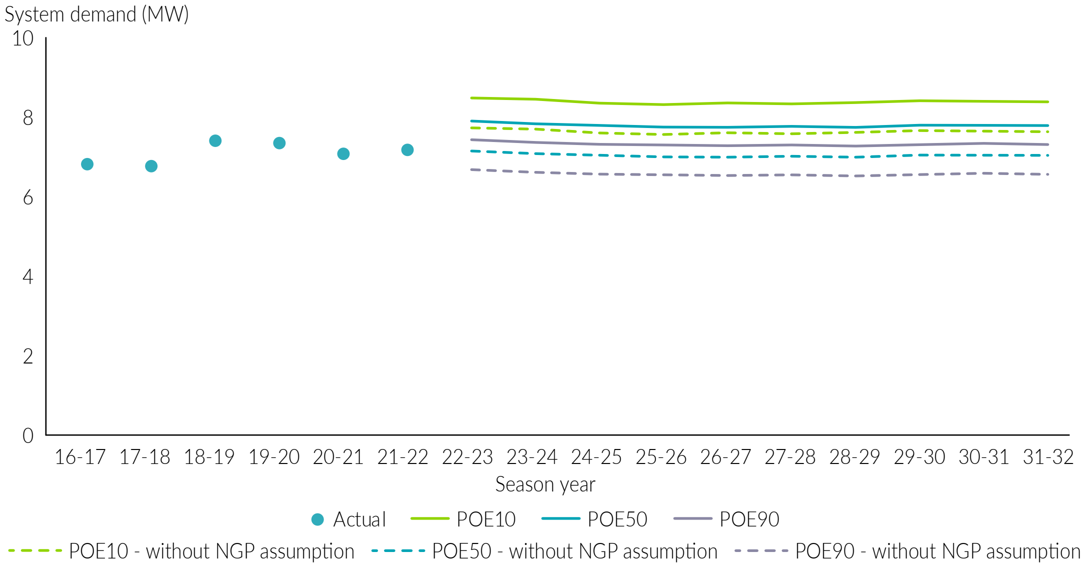
Figure 28: Historical and forecast annual system consumption for Tennant Creek by financial year, 2016-17 to 2031-32



Maximum demand

Figure 29 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Tennant Creek power system from 2016-17 to 2031-32. For Tennant Creek's maximum system demand forecasts, it was assumed that the Northern Gas Pipeline (NGP) infrastructure would be consuming 0.75 MW at times of maximum system demand. This approach was taken to capture a reasonable maximum demand extreme due to the size of the NGP relative to the system. However, the NGP only consumes from the system when its own generation is unavailable which is expected to be infrequent and not for long durations, and thus unlikely to align with maximum system demand. Figure 29 presents forecasts with and without this NGP assumption.

Figure 29: Historical and forecast maximum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2031-32



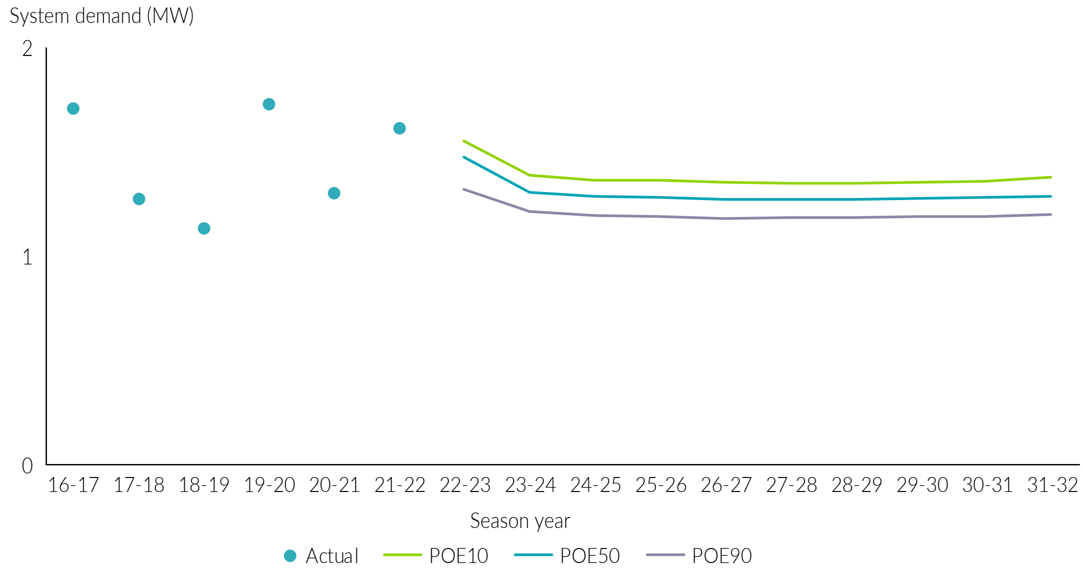
Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with cooling. The 2021-22 maximum system demand of 7.18 MW occurred in the summer season at 15:00 and is forecast to occur in the summer season between 15:30 and 17:30. The growth in maximum system demand is forecast to be relatively flat across the outlook period due to the minimal effect of population drivers and small absolute growth in distributed PV.

Minimum demand

Figure 30 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Tennant Creek power system from 2016-17 to 2031-32. For Tennant Creek's minimum system demand forecasts, it was assumed that the NGP infrastructure would not be consuming at time of minimum system demand. This approach was taken to capture a reasonable minimum demand.

Minimum system demand has historically occurred in the early morning in the shoulder season. However, in recent years its timing has deviated, with it occurring around the middle of the day in 2018-19, 2019-20 and 2021-22. The 2021-22 minimum system demand of 1.61 MW occurred in the shoulder season during the middle of the day. With additional small amounts of forecast distributed PV installed capacity in the coming years, minimum system demand is forecast to occur in the winter season during the middle of the day, between 12:30 and 14:30.

Figure 30: Historical and forecast minimum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2031-32

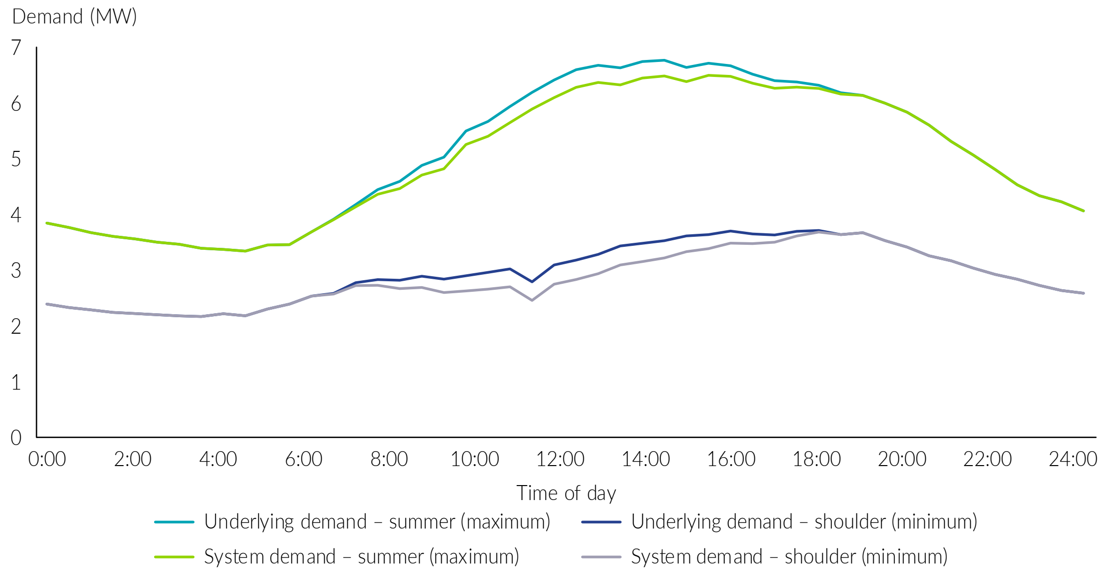


System and underlying daily load profile

Figure 31 shows typical daily load profiles under maximum and minimum system demand conditions in the Tennant Creek power system in 2021-22. The maximum demand profile represents the average of the 10 highest demand values in the summer season, whereas the minimum demand profile represents the average of the 10 lowest demand values in the shoulder season.

The blue and green lines represent the summer maximum underlying demand and system demand respectively. The dark purple and light purple lines represent the shoulder minimum underlying demand and system demand respectively. Distributed PV generation during the day has lowered maximum system demand in summer and minimum system demand in winter. The absolute minimum system demand has shifted to the middle of the day in 2021-22. However, the average of the 10 lowest demand values shows that minimum demand typically occurs in the early morning, as shown in Figure 31. Given the lower uptake of distributed PV, the observed difference between underlying demand and system demand is smaller than for the other regions.

Figure 31: Daily load profile for Tennant Creek, summer and shoulder, 2021-22



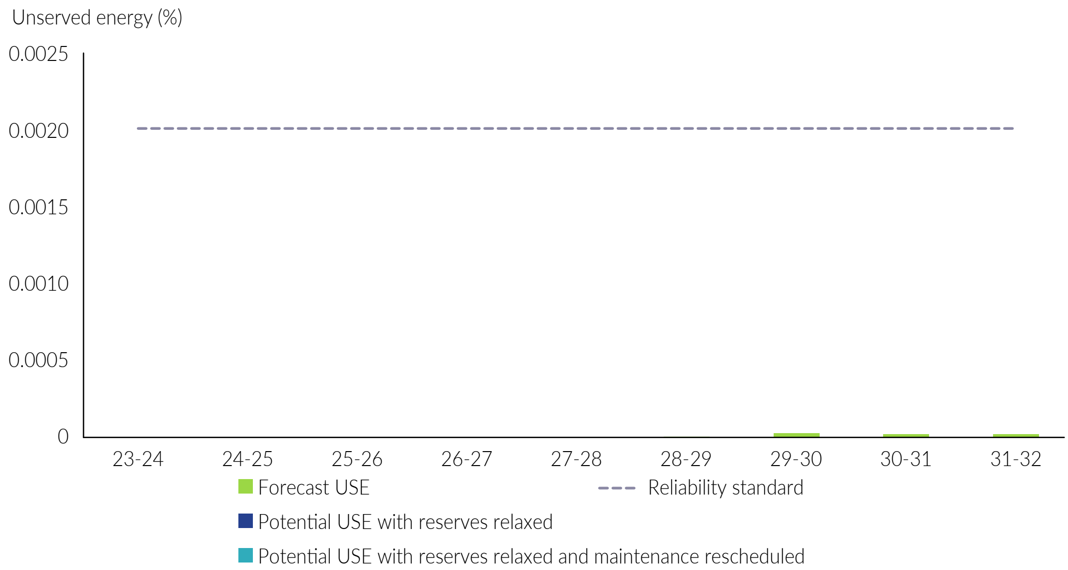
Supply adequacy outlook

This section details the results for unserved energy outcomes in the Tennant Creek power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Tennant Creek power system.

Unserved energy outcomes

Figure 32 shows there is virtually no USE forecast in Tennant Creek across the outlook period and it remains below the adopted reliability standard of 0.002% USE.

Figure 32: Forecast reliability, Tennant Creek system, 2023-24 to 2031-32

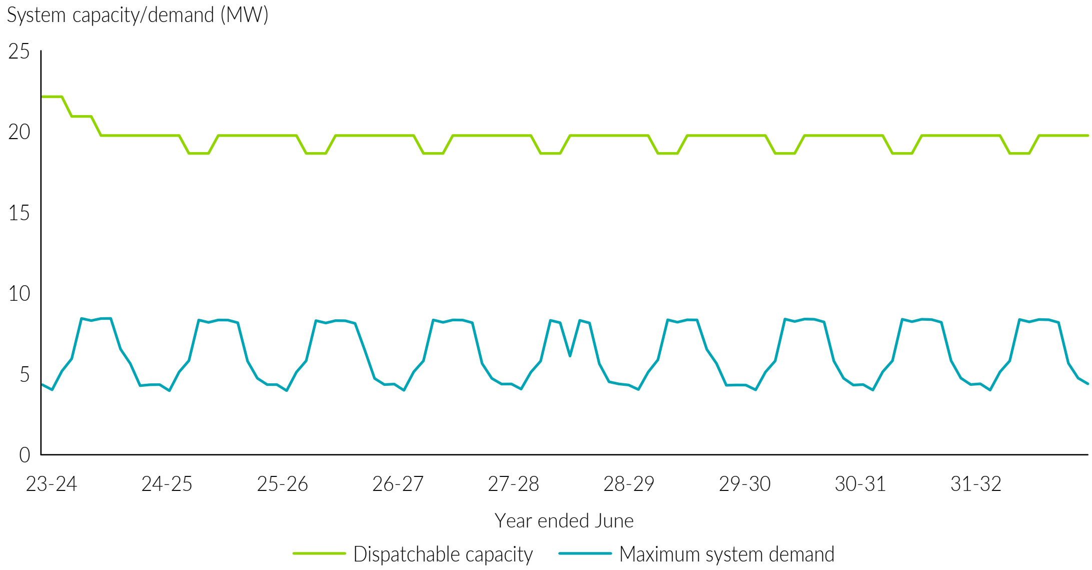


The low levels of USE forecast are mostly due to a surplus of generation capacity in the power system. Though beyond the scope of this report, there remains a possibility that USE could occur due to non-credible coincident outages across many generating units, noting that multiple contingency events have occurred in the past. Detailed USE forecasts are shown in Appendix A2.2.

Reserve capacity

As shown in Figure 33, the Tennant Creek power system has a substantial level of seasonal reserve capacity when compared with the forecast monthly maximum system demand. This results in almost no USE forecast across the outlook period. The reliability outlook in the final years of the outlook period has improved compared with the 2021 NTEOR due to a number of retirements at the Tennant Creek power station (TCPS) being 'pushed' to outside of the outlook period.

Figure 33: Forecast seasonal dispatchable thermal capacity and monthly maximum demand (POE10), Tennant Creek, 2023-24 to 2031-32



Appendix A1: Methodology and assumptions

AEMO and the Commission undertook consultation with relevant stakeholders on the methodology and assumptions for the 2022 NTEOR. This consultation occurred in December 2022 and provided an opportunity for both written and verbal feedback on the proposed assumptions. Feedback from stakeholders and the Commission was used to refine the methodology and assumptions used in the NTEOR modelling. Final assumptions are documented in this appendix by forecast component.

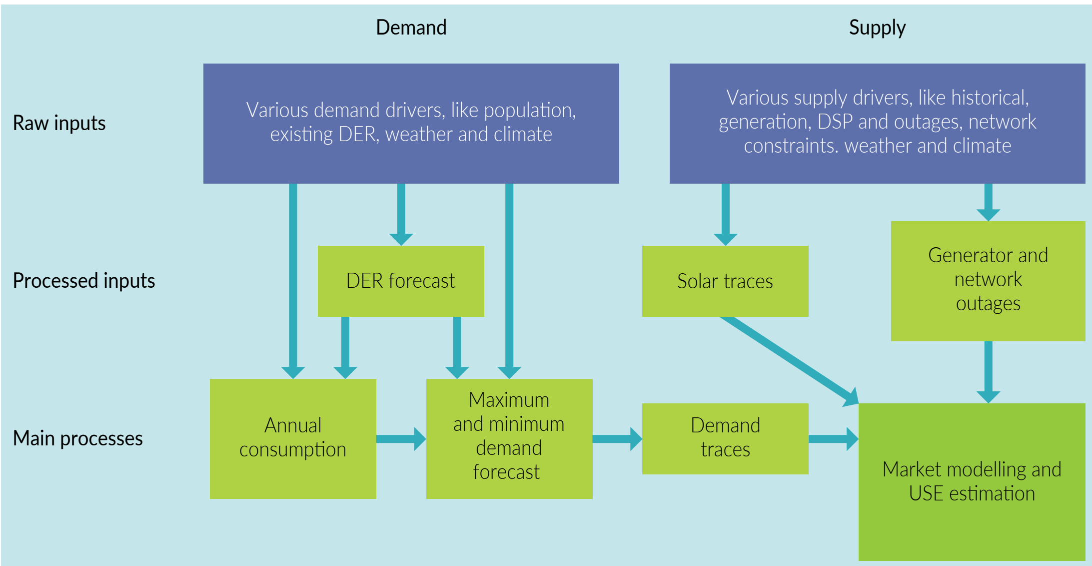
Components discussed include:

- annual electricity consumption
- maximum and minimum demand
- demand traces
- generator supply
- transmission and power system security
- supply adequacy.

A1.1 Forecast components

Production of AEMO's high level outputs requires multiple sub-forecasts to be produced and appropriately integrated; these are referred to as forecast components. In Figure 34, inputs can be seen as data streams (including forecasts provided by third parties) used directly in AEMO's forecasting process. For the NTEOR, AEMO employs a simplified process that is broadly aligned with the NEM approach. AEMO's NEM methodology documents explain some of these processed in more detail.[16] Simplifications and deviations from the NEM process are described in this appendix.

Figure 34: Forecasting components



DER: distributed energy resources; DSP: demand side participation; USE: unserved energy

16 These documents are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

DER describes consumer-owned devices that can generate or store electricity as individual units and which may have the ‘smarts’ to actively manage energy demand. This includes distributed PV systems, battery storage and electric vehicles (EVs). See Sections A1.7.6 to A1.7.8 for more detail.

Demand Side Participation (DSP) as forecast by AEMO is a subset of overall demand flexibility and is sometimes also referred to as demand response. Demand flexibility describes consumers’ capability to shift or adjust their demand. See Section A1.7.9 for more detail.

A1.2 Scenarios and uncertainty

There are two types of uncertainties in AEMO’s forecasts:

- structural drivers, which are modelled as scenarios, including considerations such as population and economic growth, and uptake of future technologies, such as distributed PV, behind-the-meter batteries, and EVs
- random drivers, which are modelled as a probability distribution and include weather drivers and generator outages.

AEMO’s forecasts in the 2022 NTEOR are focused on a single business-as-usual scenario, to explore in more detail the challenges and opportunities that may arise without further action by government and industry. The scenario assumes:

- expected growth in electricity consumption and maximum demand, consistent with forecast population and economic growth in each region
- expected uptake of distributed PV, including rooftop and small behind-the-meter PV installations, consistent with a steady continuation of current trends, and known policies
- expected uptake of behind-the-meter battery storage systems and EVs
- existing and currently committed new large-scale thermal and solar PV generators, and large-scale batteries, operational according to current economic life and project timelines
- scheduled generator decommissioning according to timelines provided by licensees
- best representation of the current power system security constraints following a review of relevant documentation and consultation.

For the random drivers, a probability distribution of their outcomes can be estimated, particularly probability distributions that represent uncertainty in consumer maximum demand and generator forced outage profiles.

The business-as-usual scenario does not explicitly consider the Northern Territory Government’s policy of 50% renewables by 2030.

A1.3 Unserved energy sensitivities

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). AEMO uses a generation adequacy assessment to determine whether available generation capacity, including an allocation for potential generation outages, and transmission capacity is sufficient to meet consumer demand consistent with the Commission's adopted reliability standard of USE not exceeding 0.002% of annual electricity system consumption. This assessment is probabilistic in the sense that it is based on the probability distributions of demand and generator outages and considers the requirement for essential system services.

While essential system services and generator maintenance are required under the majority of circumstances, AEMO has modelled three sensitivities for USE where some of these requirements may be relaxed. The three sensitivities include one:

- that considers all maintenance and essential system services to be necessary and inflexible. This is considered the base assessment of USE
- where regulating and spinning reserve requirements may be relaxed to avoid USE. While these requirements may be relaxed under some circumstances if there is insufficient capacity, AEMO notes that in not maintaining the reserve requirement to avoid USE to some consumers, overall power system operation may be less secure and at an increased risk of a major event, including a system black. These trade-offs need to be carefully managed and are not considered to be within the scope of the NTEOR
- where specified generator maintenance may be rescheduled to avoid outages. This represents a scenario where both reserve requirements and unit maintenance have been forgone to improve forecast short-term consumer outcomes, but with a potential increased risk of poorer longer-term outcomes or major events including a system black. These trade-offs between short and longer-term risks need to be carefully managed and are beyond the capability of the simulation applied in the NTEOR.

A1.4 Northern Territory power systems

The 2022 NTEOR includes analysis on the Territory's three largest power systems. Isolated systems in remote communities that are not connected to one of the three power systems are not considered in the NTEOR.

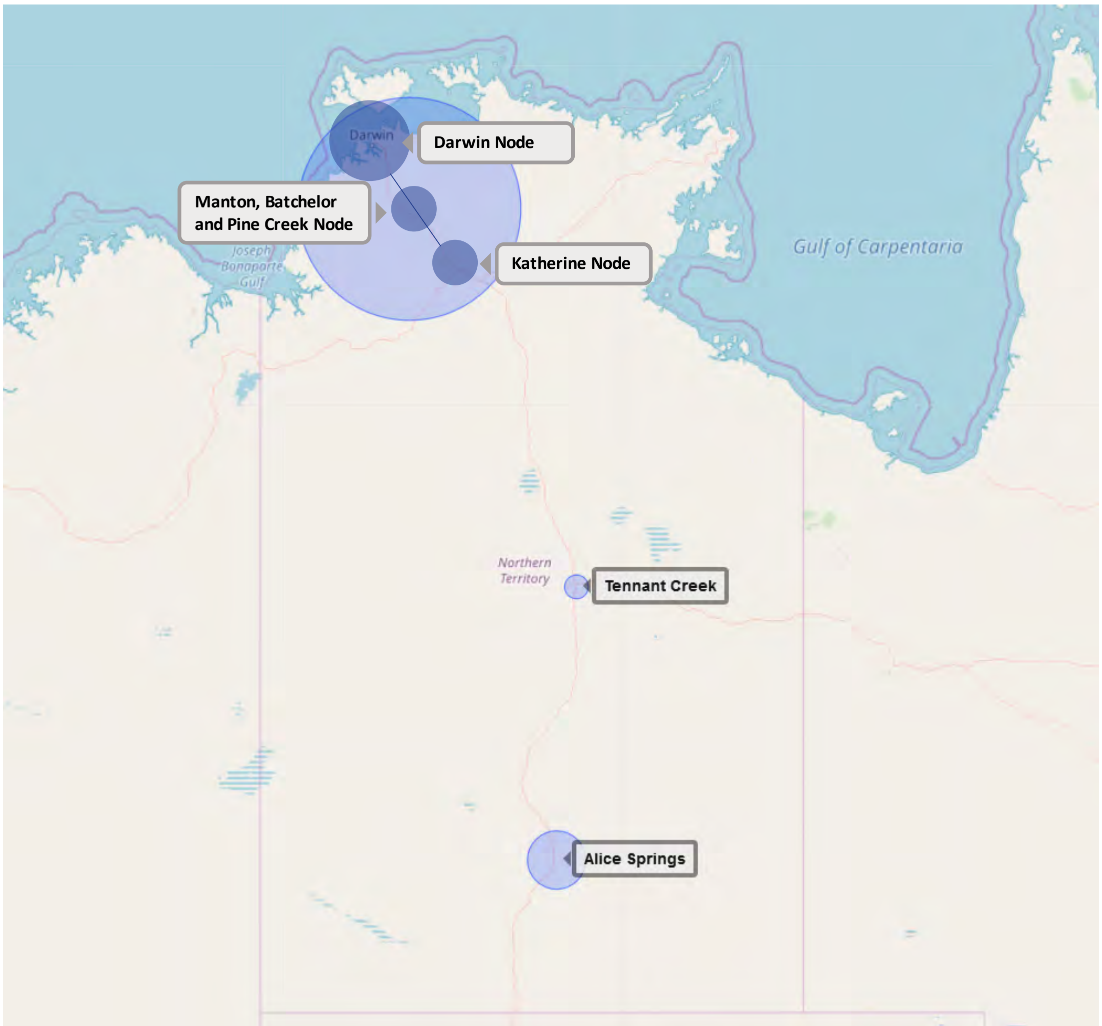
The Darwin-Katherine power system is modelled as a whole region, and also split into three subregional nodes for modelling purposes, as listed below. These three subregional nodes are connected by a 132 kV transmission line that may support the neighbouring region within the line's limitations. By modelling each node separately, the outlook can better identify challenges and opportunities in each subregion in addition to the broader regional analysis.

The three power systems and relevant Darwin-Katherine power system subregional nodes (for modelling purposes) in the Territory are:

- Darwin–Katherine
  - Darwin
  - Manton, Batchelor and Pine Creek
  - Katherine
- Alice Springs
- Tennant Creek.

The Darwin-Katherine, Alice Springs and Tennant Creek power systems are not connected to each other by transmission infrastructure. The general location of each system and subregional node considered in the 2022 NTEOR is shown in Figure 35.

Figure 35: Spatial representation of the Territory's three largest power systems and Darwin-Katherine subregional nodes



A1.5 Annual electricity consumption methodology

The annual electricity consumption forecasts are designed to capture the main actual and expected drivers in electricity consumption and trends over the 10-year outlook period.

The foundation of the annual energy consumption forecast is a weather-based regression model, used to create a 'base year' forecast that represents the consumption in a year with typical weather conditions. The model was built using daily system consumption data together with weather data from Bureau of Meteorology (BOM) stations in close proximity to the Territory's consumption centres.

The base year was then projected forward on an annual basis, applying forecast growth in population and uptake of residential and commercial distributed PV generation.

As with previous forecasts, gross state product (GSP) was not used as a growth driver. Statistical analysis suggests its correlation with energy consumption in the Territory remains weak.

Large load variations representing changes in industrial consumption are included as step changes in the consumption forecasts. Block load assumptions used in consumption, maximum and minimum demand forecasts are described in Section A1.7.5.

A1.6 Maximum and minimum demand methodology

For forecasting maximum and minimum demand, AEMO applied a regional demand forecasting methodology, in line with the high temporal resolution demand models AEMO uses in forecasting maximum and minimum demand in the NEM.[17]

The methodology used for the Territory forecasts provides probabilistic demand forecasts by season, as the demand is dependent on weather conditions (primarily temperature), and includes a degree of stochastic variability, because these conditions vary from season to season, as well as year to year.

Due to this variability, maximum and minimum demand forecasts are expressed as POE values from a distribution, rather than a point forecast. For any given season or year:

- 10% POE maximum demand value is expected to be exceeded, on average, one year in 10
- 50% POE maximum/minimum value is expected to be exceeded, on average, one year in two
- 90% POE minimum demand value is expected to be exceeded, on average, nine years in 10 (that is, actual minimum demand is expected to be lower than the 90% POE minimum demand for, on average, one year in 10).

17 See Electricity Demand Forecasting Methodology Information Paper, August 2022, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf?la=en

The three subregional nodal maximum and minimum demand forecasts for the Darwin-Katherine power system (Darwin; Manton, Batchelor and Pine Creek; and Katherine) were first developed on a non-coincident basis. They were non-coincident because they were forecast independently and their maximum and minimum demands did not necessarily coincide with the time of the overall power system's (Darwin-Katherine) aggregated maximum and minimum demand. Coincident forecasts, on the other hand, represent the demand of the subregional nodes coinciding with the time of the overall power system's aggregated maximum and minimum demand. AEMO accounted for this diversity in timing of maximum and minimum demand through the use of diversity adjustment factors, represented by:

$$Regional\ Forecast = \sum (Noncoincident\ subregional\ forecast_r * diversity\ adjustment\ factor_r)$$

A1.7 Demand assumptions

A1.7.1 Demand definitions

In this methodology, "system demand" was provided by PWC System Control and included output from all large-scale generation. It was provided for the following power systems or nodes:

- Darwin–Katherine
  - Darwin
  - Manton, Batchelor, and Pine Creek
  - Katherine
- Alice Springs
- Tennant Creek

AEMO's demand forecasts are typically developed on a 'sent-out' basis representing electricity to be supplied to customers from the network. However, system demand data provided by PWC System Control included generator auxiliary load (electricity used on-site by the generator) for existing Territory Generation owned generators whilst other generator connections were metered net of auxiliary loads. Therefore, the system demand data itself was a hybrid of system demand on an 'as-generated' basis for the Territory Generation portion and system demand on a 'sent out' basis for the remaining generators. The demand forecast presented aligned with this hybrid definition. In addition, AEMO's modelling of generator capacity aligned with this definition, as described in Section A1.8.7.

Similarly, system consumption is defined as energy generated over time and is expressed in megawatt-hours (MWh) or similar.

Demand modelling was performed on underlying demand, which is an estimate of all the power used by consumers from the power point, from any source (including both the network and distributed PV installed by residential or commercial consumers). This produces a tight relationship between demand and weather, allowing the impact of distributed PV to be modelled separately. Distributed PV impacts were then coupled to the underlying demand model results inside the simulation engine to derive system demand.

Electricity usage associated with transmission and distribution losses was not removed in the calculation of underlying demand. Therefore, transmission and distribution losses have not been explicitly considered in demand projections. All modelling based on this definition of demand implicitly assumes that the effect of transmission and distribution losses will remain consistent with history throughout the entire outlook period.[18] Due to this assumption, underlying demand's calculation is system demand with the addition of behind the meter contribution.

Underlying consumption refers to underlying energy consumed, and is calculated similarly to underlying demand, and is expressed in MWh or similar.

A1.7.2 Season definitions

The demand forecasts were modelled at the season level and presented as a season year (year ending 31 August). These are the:

- summer season (wet, in the case of Darwin–Katherine), which is defined as 1 November to 31 March
- winter season (dry, in the case of Darwin–Katherine), which is defined as 1 June to 31 August
- shoulder season, which is defined as the months September, October, April and May.

AEMO consulted with the BOM in relation to the above seasonal definitions but did not identify a need to revise the definitions from a climate perspective.

Demand simulations were performed across forecast years using the seasonal model appropriate to the time of year. Probabilistic forecasts were derived from this set of simulations, partitioned into season years, where season years are between 1 September and 31 August. The supply adequacy assessments and input demand traces were, however, developed on a financial year basis.

A1.7.3 Demand data and network information

PWC Power Services and PWC System Control provided:

- demand data, which is used to conduct historical analysis and construct forecasting models. Half-hourly data for each of the five regions was included
- network information on outage events, used to assist in cleaning historical demand data
- information about industrial demand changes, future load transfers, and anticipated new load
- a record of distributed PV installations, used to calculate historical and forecast distributed PV generation.

18 For information, PWC Power Services estimated for the Darwin-Katherine power system a transmission loss rate of 2.9% and a distribution loss rate of 2.1% when considering total system consumption in 2021-22. Similarly, the transmission and distribution losses for the Alice Springs power system were estimated to be 2.2% and 3.1%, respectively. The distribution losses in the Tennant Creek power system were estimated to be 6.1% in 2021-22.

A1.7.4 Economy and population

Forecasts of population, summarised in Table 1, are based on five-year long-term averages using Australian Bureau of Statistics (ABS) statistical area information. Population growth rates have been developed using population projections from the Northern Territory Government's Department of Treasury and Finance.[19]

Table 1: Population growth rates adopted for demand forecast

	Population growth rate (per annum) (%)			
Region	2021-22 to 2025-26	2026-27 to 2030-31	2031-32 to 2035-36	ABS statistical areas
Darwin-Katherine	1.23	1.60	1.68	-[1]
Darwin	1.39	1.80	1.86	Greater Darwin (SA4)
Katherine	0.66	0.83	1.07	Katherine (SA3)
Manton, Batchelor and Pine Creek	0.58	0.70	0.75	Daly-Tiwi-West Arnhem (SA3)
Alice Springs	0.56	0.58	0.65	Alice Springs (SA3)
Tennant Creek	-0.39	0.11	0.26	Barkly (SA3)

1. Growth rates for Darwin-Katherine were back calculated after summating the subregional population values.

Forecast GSP, as noted in Section A1.5, has not been adopted as an indicator of electricity consumption for the Territory's three power systems. Statistical tests have verified that GSP is not directly indicative of economic activity in Tennant Creek and Alice Springs, nor of the electricity consumption in the Darwin–Katherine system due to LNG projects that contribute significantly to GSP but consume relatively little or no electricity from the power system. Limitations on spatial data availability also prevent GSP projections from being adequately assigned to the power systems, or nodes.

19 Population growth rates have been developed using population projections from the Northern Territory Government's Department of Treasury and Finance. Relevant projections can be found at https://treasury.nt.gov.au/dtf/economic-group/population-projections

A1.7.5 Block load changes

Significant load changes explicitly modelled in the annual electricity consumption, maximum and minimum demand forecasts are described in Table 2. AEMO collected block load (step changes in demand caused by large customers connecting/expanding or disconnecting/contracting, or changing demand patterns) information from PWC Power Services and determined which projects are likely to connect or disconnect over the outlook period. Block loads that are material to the forecasts and are not otherwise captured through drivers such as population, were modelled explicitly by AEMO.

Key sites featured in the forecasts were in:

- Darwin – a new mine development is expected to commence early in 2023-24. This load is expected to further increase at the start of the 2025-26 financial year.
- Darwin – an LNG-related load is expected to be connected late in 2022-23. This load is anticipated to be in operation until the end of 2023-24.
- Manton, Batchelor and Pine Creek - a new pumping station at the Darwin River Dam is expected to connect early in 2023-24.
- Katherine – upgrades to the existing RAAF Base Tindal are expected to increase electricity consumption from the middle of 2024-25
- Alice Springs – the existing JDFPG site is expected to connect to the network towards the middle of 2023-24.

A mining development previously forecast for Tennant Creek is no longer considered in these forecasts.

Table 2: Block load assumptions for annual consumption, maximum and minimum demand

Region/node	Site	Effective date	Status
Darwin	Mine development stage 1	1/10/2023	Connect
Darwin	Mine development stage 2	1/07/2025	Connect
Darwin	Temporary LNG project	1/03/2023 to 30/06/2024	Connect
Manton, Batchelor, and Pine Creek	Darwin River Dam pumping station	1/10/2023	Connect
Katherine	RAAF Base Tindal upgrade	1/01/2025	Connect
Alice Springs	JDFPG	1/01/2024	Connect

A1.7.6 Residential and commercial PV

Installed PV capacity was split into residential, commercial, and large-scale (network-connected) PV:

- residential and commercial PV systems (referred to as distributed PV) offset system demand, that is demand met by large-scale network-connected generators
- large-scale PV systems operate as large-scale network-connected generators and therefore contribute to network-supplied energy. This is discussed in Section A1.8.

Historical records of residential and commercial PV system installations were provided by PWC Power Services and were used as a foundation for the PV forecasts. For the 2022 NTEOR, historical records of residential and commercial PV system installations were refreshed resulting in actuals data differing to the 2021 NTEOR. This has subsequently flowed into revisions in the installed rates used in the PV projections compared with the 2021 NTEOR. Future changes to PWC's Embedded Generation policy[20] were not included in the 2022 NTEOR due to uncertainties with the policy and insufficient data to determine the impact of the policy with respect to PV system sizes.

Zero-export limits that may be imposed on PV systems were not considered in the 2022 NTEOR. Conceptually, zero-export limits may impact consumers' payback and lead to a moderation of further PV uptake. The modelling of zero-export systems is considered by AEMO to be very complex and further data and advice from PWC would be required. Where necessary, consideration of changes to the Embedded Generation policy and zero-export PV systems will be examined again in future NTEORs.

The PV projections were based on the following assumptions:

- for residential systems:
  - in April 2020, the Northern Territory Government changed the solar PV incentive framework of Jacana Energy (the retailer for the majority of customers in the Territory) by replacing the premium 1-to-1 feed-in tariff (FiT) with 8.3c/kilowatt hour (kWh) for new installations, for new customers with existing installations, and for existing customers that make changes to their existing installation. Furthermore, in May 2022, the Northern Territory Government announced that from 1 July 2022, customers who have been on the premium FiT for four years would transfer to the standard FiT. Although the winding back of these programs has slowed the rate of distributed PV installations, new installations are forecast to continue strongly during the outlook period. This analysis is supported by historical examples from other Australian jurisdictions where the feed-in-tariff has reduced, such as in South Australia in 2011. Furthermore, the rate of distributed PV installations has been increasing across all of Australia regardless of feed-in-tariff, as the cost of systems has reduced
  - modelling assumed that 85% of new dwellings have PV installed throughout the outlook period, and installations on existing dwellings will continue at current rates. While the percentage for new dwellings is not data-driven, AEMO considers it a reasonable assumption for forecasting purposes. The overall impact is materially low as commercial and existing residential dwellings dominate the PV installed capacity forecasts

20 See PWC's consultation document on changes to the Embedded Generation policy, at https://www.powerwater.com.au/customers/power/solar-power-systems/pv-class-requirements.

- the base estimate of total residential installation rate for Darwin is 1,337 per year (the number of installations between 2017 and 2022 have ranged from 612 to 2,448 per year). The adopted rate for the Manton, Batchelor and Pine Creek region is 26 residential systems per year (the number of installations between 2017 and 2022 has ranged from 13 to 37 per year) and the rate for the Katherine region is 69 residential systems per year (the number of installations between 2017 and 2022 has ranged from 42 to 123 per year). The adopted rate for Alice Springs is 202 per year (the number of installations between 2017 and 2022 has ranged from 60 to 285 per year), and for Tennant Creek it is two per year (the number of installations between 2017 and 2022 has ranged from 0 to 13 per year)
- the installation rate was tapered in the Darwin and Manton, Batchelor and Pine Creek regions during the later stages of the outlook period. This attempts to capture the effects of saturation by ensuring installation rates relative to the estimated number of remaining dwellings without PV remain approximately constant. Other regions were not tapered over the outlook period given their current lower saturation levels
- in the Darwin and Alice Springs regions, the new residential system size is forecast to grow marginally over the outlook period based on a linear trend of the most recent four years of installation data. Due to volatility in historical system sizes, the Manton, Batchelor and Pine Creek region and the Katherine region, adopt the same system size forecast as Darwin. Similarly, Tennant Creek adopts the same system size forecast as Alice Springs
- residential system totals represent the sum of systems reported by PWC Power Services as having the classification 'Private'

• for commercial systems:
  - installations were assumed to continue at rates resembling those seen in the years preceding 2022-23 (45 installations per year in the Darwin region, one per year in the Manton, Batchelor and Pine Creek region, three per year in the Katherine region, 13 per year in Alice Springs, and one per year in Tennant Creek). These forecasted installations are in addition to any upcoming solar projects (between 100 and 2000 kVA) which have been identified by PWC Power Services
  - for the Manton, Batchelor and Pine Creek subregion, modelling adopted the 2021-22 average installed capacity for new forecast commercial systems. For the Darwin and Katherine subregions, and Alice Springs and Tennant Creek regions, where greater variability in historical data is observed, modelling incorporated data from earlier years. The average value drew upon data from 2018-19 to 2021-22 for Darwin and Katherine, 2019-20 to 2021-22 for Alice Springs and 2015-16 to 2021-22 for Tennant Creek
  - for Darwin, Katherine, Alice Springs and Tennant Creek regions/subregions, AEMO has factored in information received from PWC Power Services regarding upcoming solar projects (between 100 and 2000 kVA). This is most noticeable in Tennant Creek where several sizeable installations are expected to come online in 2023-24
  - the commercial sector totals represent the sum of systems reported by PWC Power Services as having the classification 'Commercial'

- for large-scale PV systems:
  - existing and future systems are considered to contribute to meeting system demand, and were modelled on the supply side, not the demand side. These systems are discussed in Section A1.8 below.

Residential and commercial PV generation was derived using half-hourly estimates of generation for each power system, or node, normalised to a kilowatt (kW, output) per kW (installed capacity) basis.

Consistent with previous NTEOR forecasts, AEMO used a third-party provider to deliver normalised distributed PV generation estimates.

The impacts of distributed PV system damage and degradation can either be captured as an adjustment to the installed capacity, or through the applied normalised generation profiles. To avoid double counting, such damage and degradation should be clearly addressed in one or the other, but not both. AEMO accounted for the degradation of distributed PV output in the distributed PV normalised generation profiles, not in installed capacity to avoid double counting of degradation.

The assumptions above result in the following distributed PV forecasts. Figure 36, Figure 37, Figure 38, Figure 39, Figure 40, and Figure 41 show forecasts for: the whole of Darwin-Katherine; Darwin; Manton, Batchelor and Pine Creek; Katherine; Alice Springs; and Tennant Creek, respectively, compared with forecasts used in the previous NTEOR.

Figure 36: Aggregated historical and forecast distributed PV capacity, Darwin–Katherine power system, 2016-17 to 2031-32

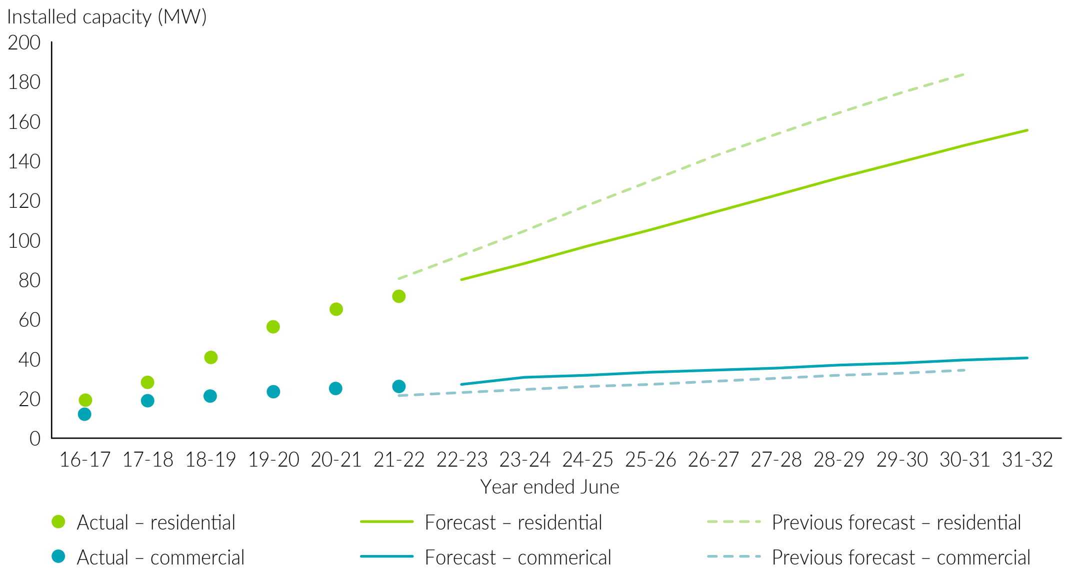


Figure 37: Historical and forecast distributed PV capacity, Darwin node, 2016-17 to 2031-32

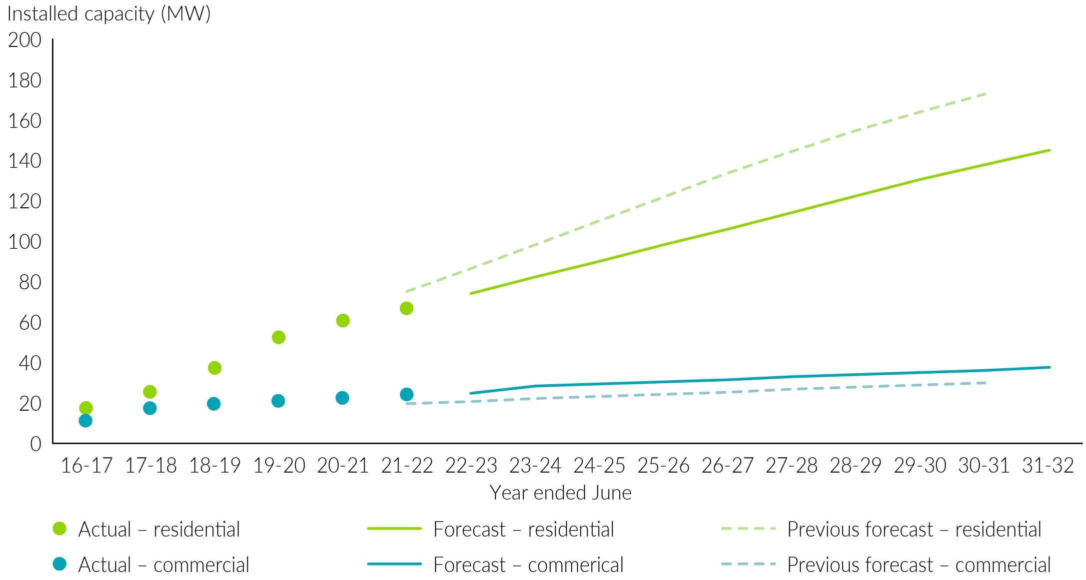


Figure 38: Historical and forecast distributed PV capacity, Manton, Batchelor and Pine Creek node, 2016-17 to 2031-32

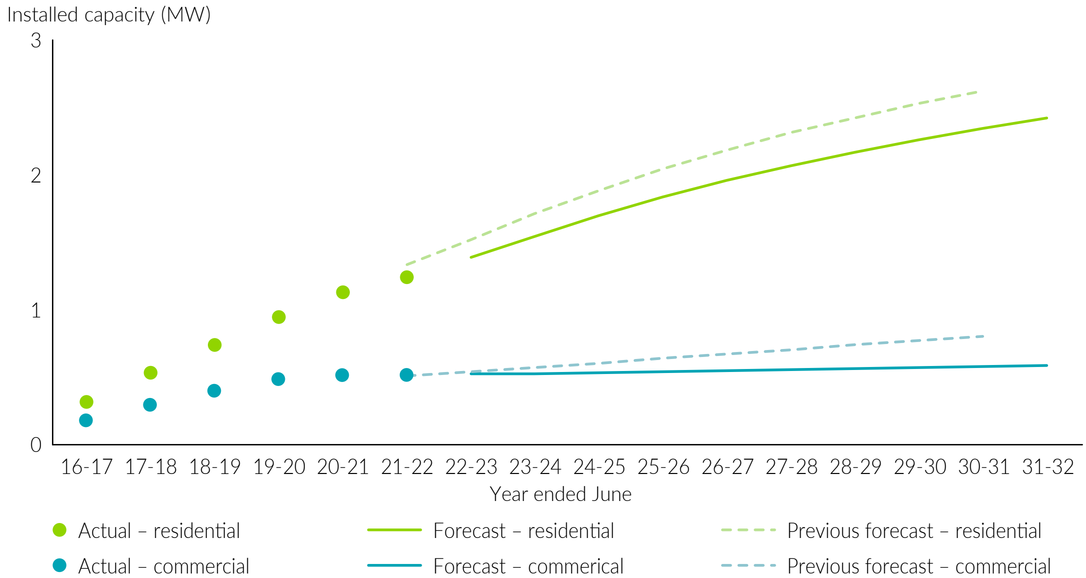


Figure 39: Historical and forecast distributed PV capacity, Katherine node, 2016-17 to 2031-32

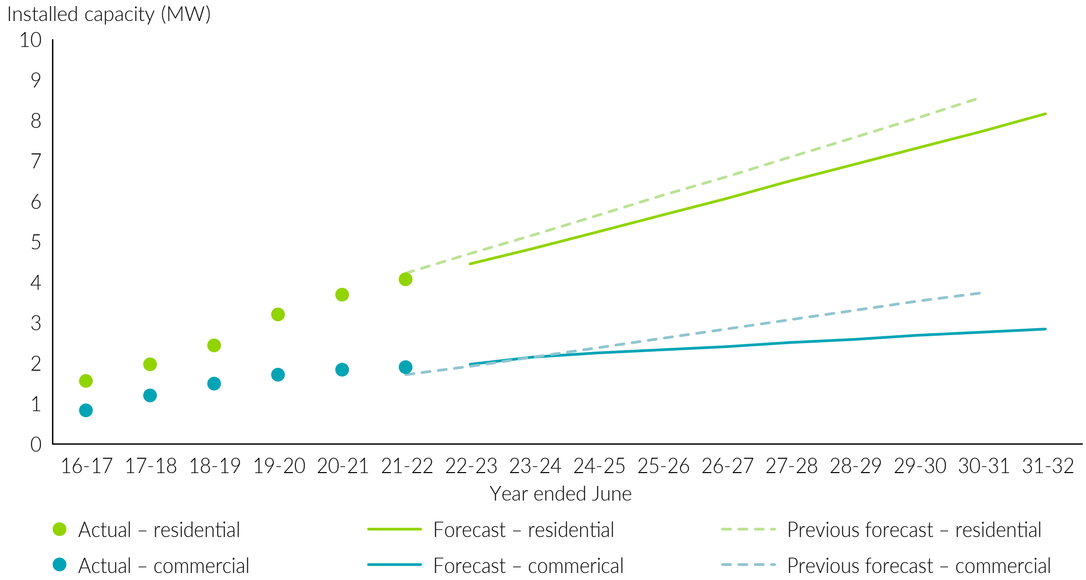


Figure 40: Historical and forecast distributed PV capacity, Alice Springs power system, 2016-17 to 2031-32

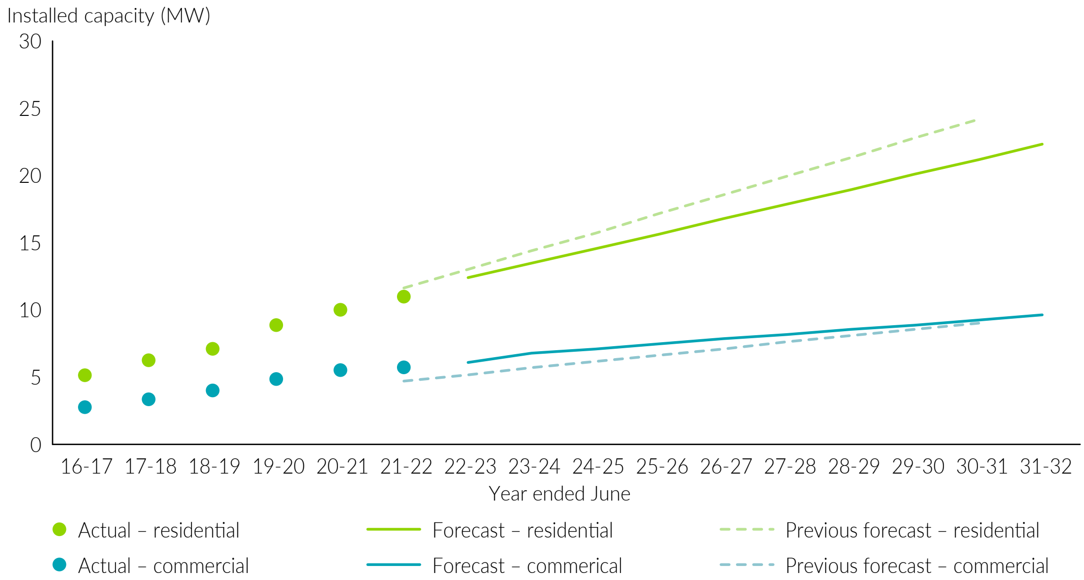
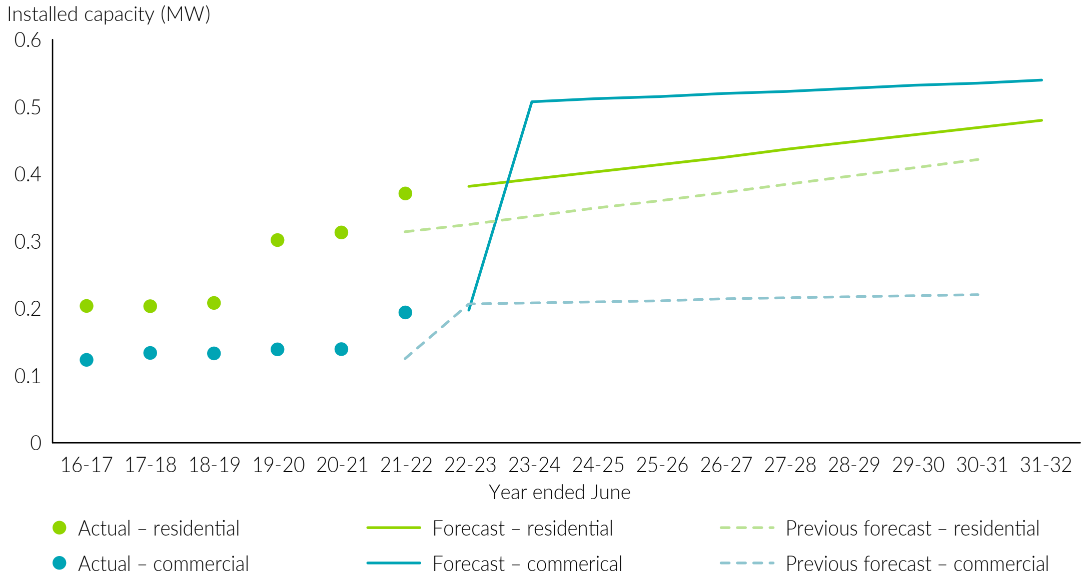


Figure 41: Historical and forecast distributed PV capacity, Tennant Creek power system, 2016-17 to 2031-32



A1.7.7 Behind-the-meter battery storage

The uptake of behind-the-meter storage systems was considered to have an impact on forecast annual maximum and minimum demand for each region.

The battery contribution was accounted for by considering a set of battery charge and discharge profiles in conjunction with battery installed capacity to give a half hourly time series capturing the impacts from behind-the-meter batteries. The charge and discharge profiles had the effect of smoothing out demand across the day and reducing maximum demand.

The charge and discharge profiles and battery power forecasts were adopted from AEMO's work in the NEM. Specifically, Queensland charge and discharge profiles under AEMO's NEM Progressive Change Scenario were used and forecasts of battery capacity from Queensland were allocated to each Territory power system, or node, on a per capita basis. A scaling factor was further applied to ensure the forecasts in each Territory power system, or node, approximately started from known installation levels, which assumed the average battery system power rating of 5 kW. Based on the actual number of batteries installed, 3.83 MW, 0.29 MW and 0.18 MW was used in the: Darwin; Manton, Batchelor and Pine Creek; and Katherine nodes respectively, and 0.98 MW in Alice Springs, for 2021-22. Further, no installations had been recorded in Tennant Creek during 2021-22, however battery capacity has been assumed to increase in 2022-23.

While AEMO is aware of the Northern Territory Government's Home and Business Battery Scheme, the scheme was not explicitly considered in the 2022 NTEOR.

Situations where control of a battery is determined by an aggregator, commonly referred to as a virtual power plant (VPP), were not considered in the 2022 NTEOR as the Commission does not consider any proposed commercial applications of VPPs in the Territory meet its threshold for being considered as committed. While the Commission is aware of a small trial VPP in Alice Springs as part of the Alice Springs Future Grid project, the Commission notes it is a trial.

A1.7.8 Electric vehicles

The uptake of EVs on the annual electricity consumption, maximum and minimum demand forecasts of each region was considered in the 2022 NTEOR.

The impact of the EV contribution to the forecasts was accounted for by considering EV charging profiles in conjunction with the number of EVs to give a half hourly time series capturing the impacts from EVs.

The EV charging profiles, and vehicle uptake forecast were adopted from AEMO's work in the NEM. Similar to behind-the-meter batteries, Queensland forecast data under the NEM Progressive Change Scenario was used and allocated to each Territory region or node on a per capita basis. A scaling factor was further applied to ensure the forecasts in each Territory region or node approximately started from known EV numbers (Battery EVs and Plug-in Hybrid EVs.

A1.7.9 Demand-side participation

There is currently no measurable demand-side participation instrument in use in Territory regions, and this was assumed to persist over the outlook period.

AEMO note that the modelling assumed a degree of demand flexibility arising from the battery storage and EV charging profiles.

A1.7.10 Half-hourly demand traces

Demand traces (referred to as demand time-series in general terms) were prepared by deriving a trace from a historical reference year (financial-year) and growing (scaling) it to meet specified future characteristics. This was achieved through a constrained optimisation function which minimised the differences between the grown trace and the demand targets.

The Territory demand traces were grown using a similar methodology to the one AEMO uses for the NEM.[21] The traces were prepared on a financial year basis, to various targets, categorised as:

- maximum summer demand (at a specified POE level)
- maximum winter demand (at a specified POE level)
- minimum demand (at a specified POE level)
- annual energy (consumption).

Traces are differentiated by:

- Territory power system or node
- target year
- POE level.

21 See Electricity Demand Forecasting Methodology Information Paper, August 2022, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf?la=en

The trace development process was conducted in two passes for each combination of Territory power system or node, historical reference year, target year, scenario and POE level:

- pass 1 - grow the reference year trace on an operational demand as sent out (OPSO)-lite basis to meet OPSO-lite targets (demand trace has forecasts of technology components [rooftop PV, non-scheduled PV] removed)
- pass 2 - reinstate forecasts of technology components and reconcile the time series to meet the OPSO targets.

For the 2022 NTEOR, two demand traces were developed using the reference years of 2015-16 and 2016-17. These two years were selected as they provided diversity in terms of inherent monsoonal activity within the Territory with 2016-17 being a monsoonal year and 2015-16 having substantially drier than normal conditions. In addition, given the features of the Territory's power systems, which requires consideration for the correlation between PV and demand (irradiance and temperature), the use of two distinct historical reference years is considered sufficient.

A1.8 Supply assumptions

This section details and explains the assumptions used to model the supply system in each of the Territory power systems or nodes. The model developed with these assumptions was used to undertake simulations of future dispatch outcomes to assess system reliability.

A1.8.1 Power station parameters

The results of simulations of electricity supply were driven by the technical parameters of the generators used in the models. Table 3 outlines the key parameters used and describes how they were incorporated in the supply adequacy modelling. Inputs and assumptions were based on information provided by licensed generators.

Table 3: Summary of generator technical parameters

Parameter	Description
Maximum capacity	Nameplate capacity of each generating unit.
Rating	Reflects the impact of seasonal temperature on generator available capacity. This value overrides the maximum capacity.
Minimum stable level	Minimum stable load for generation.
Outage schedule	Planned outage schedule of units. AEMO applied the 10-year outage plan provided by licensed generators.
Outage rates	Historical unplanned failure rates that describe the probability of capacity deration of each technology.
Mean time to repair	Average time required to repair a failed unit and return it to normal operating conditions.
Auxiliary rate	The expected rate of unit and station auxiliary load as a percentage of expected maximum output.

A1.8.2 Power station retirements

Based on information provided by licensed generators, AEMO modelled the retirement of generating units at the the RGPS, TCPS and CIPS. Based on advice previously provided by Territory Generation, the life of TCPS units 10-14 and KPS units 1-3 was extended and the retirement of these units were not considered in the 2022 NTEOR. Table 4 shows the future retirement dates used in the simulation and the units that have recently retired and thus were not included in the 2022 NTEOR supply adequacy assessment.

Table 4: Power station retirements

Power station	Power system/ node	Units	Estimated summer capacity (MW)	Assumed retirement date
RGPS[1]	Alice Springs	3	4.0	31 December 2025
		4	4.0	31 December 2025
		5	4.0	31 December 2025
		6	5.2	31 December 2025
		7	5.2	31 December 2025
		8	5.2	Retired
		9	12.8	31 December 2025
TCPS	Tennant Creek	1	1.1	31 December 2023
		2	1.1	Retired
		3	1.1	Retired
		4	1.1	Retired
		5	1.1	31 December 2023
CIPS	Darwin	1	30.0	31 December 2026
		2	30.0	31 December 2026
		3	30.0	Retired
		4	30.0	31 December 2027
		5	30.0	31 December 2027
		6	30.4	31 December 2027
		7	34.2	31 December 2029

1 RGPS retirements dates have been provided by Territory Generation, however it has advised that the dates are not 'firm' and subject to the reliable operation of the OSPS.

A1.8.3 Power station upgrades and new entrants

In addition to the existing power generation fleet, AEMO considered all the committed projects expected to come online during the outlook period. A committed project is a project which the Commission considers has demonstrated sufficient development progress and is highly likely to proceed, with major milestones reached, such as a Commission-issued licence to operate in the Territory's electricity supply industry, relevant PWC connection agreement executed (generation or load), final investment decision reached (private industry projects), and approved government funding (public projects). The Commission intentionally takes a conservative approach in order to capture an accurate business-as-usual scenario. All the new entrant power stations, generators and battery energy storage systems considered as committed projects and included in the modelling are listed in Table 5. All of these projects are planned to connect to the Darwin–Katherine power system.

Table 5: Committed projects considered for 2021 NTEOR forecasts

Project name	Licensee	Power system/node	Units	Fuel/ technology	Estimated summer capacity (MW)	Start date used for modelling purposes[1]
HCPS	HCPS Co Pty Ltd	Darwin	6	Gas	14.5[1]	01 April 2024[2]
Batchelor 2 Solar Farm power station (Batchelor 2)	BSF Co Pty Ltd	Manton, Batchelor and Pine Creek	-	SAT solar	10	30 December 2023[2]
Batchelor Solar Farm power station (BSPS)	Eni Australia Limited and Eni New Energy Batchelor Pty Ltd	Manton, Batchelor and Pine Creek	-	SAT solar	10	31 December 2023
Manton Dam Solar Farm power station (MSPS)	Eni Australia Limited and Eni New Energy Manton Dam Pty Ltd	Manton, Batchelor and Pine Creek	-	SAT solar	10	31 December 2023
Katherine Solar power station (KSPS)	Eni Australia Limited and Eni New Energy Katherine Pty Ltd	Katherine	-	SAT solar	25	31 December 2023
Darwin BESS	Territory Generation	Darwin	-	BESS	32.6[3]	30 April 2024
CIPS 10	Territory Generation	Darwin	1	Gas	22.2	30 December 2024
RAAF Darwin	Assure Energy Asset Pty Ltd	Darwin	-	Fixed flat plate (FFP) solar	2.9	05 September 2023
Robertson Barracks	Assure Energy Asset Pty Ltd	Darwin	-	FFP solar	8.9	28 September 2023

1. It is understood the units will be block-loaded in a block of five, and no more than five units will operate at any given time.
2. Modelling assumed that these units will be fully available six months after the last start date provided by licensees.
3. The BESS does not supply energy in the supply adequacy assessment, however it is expected to impact security requirements, which indirectly improves supply availability.

Territory Generation's new Darwin BESS was considered strictly as a system reserve provider and only contributed to the system security requirements in the supply adequacy assessment simulation. This contribution can improve the availability and dispatch of other units in the supply adequacy assessment. For modelling purposes, AEMO assumed Darwin BESS meets all security requirements currently provided by a Frame 6 machine.[22]

HCPS Co Pty Ltd advised that one of the six units at the HCPS will always operate as a back-up, in case of unplanned outages in any of the other units. The back-up unit will not be dispatched to reduce the system's USE, nor to limit reserve and inertia shortages. This operational characteristic was included in the model. Furthermore, it is understood the units will be block-loaded in a block of five; this aspect was included in the modelling.

Six large-scale solar projects amounting to 69.33 MW were considered to be committed in the Darwin-Katherine power system. Proposed large-scale solar PV projects that did not meet the Commission's threshold for being considered as committed projects were not considered for modelling purposes.

A1.8.4 Solar traces

The generation of both fixed flat plate (FFP) and single axis tracking (SAT) solar projects were simulated using the System Advisor Model (SAM)[23] developed at the National Renewable Energy Laboratory.

The SAM calculates hourly solar generation output based on project characteristics such as the panel technology type (FFP, SAT, or dual axis tracking) and nameplate capacity, solar irradiance data, and weather conditions.

Irradiance and weather data were used in the SAM to create hourly PV generation traces for the reference years 2015-16 and 2016-17. The data was sourced from the BOM weather station closest in latitude and longitude to each project. The two reference years were used to forecast demand (based on historical temperature), to ensure a realistic correlation between solar generation and demand. Given the features of the Territory's power systems, which requires consideration for the correlation between PV and demand (irradiance and temperature), the use of two distinct historical reference years was considered sufficient.

A1.8.5 Exclusion of black start generators

Black start generators are not considered to contribute to supply capacity. As such, consistent with previous NTEOR supply adequacy assessments, they were not considered in the 2022 NTEOR. Consistent with the purpose of supply adequacy assessments, which only consider a system in a secure state, black start generators are assumed to not contribute to capacity for the purpose of the NTEOR given black start generation is intended for recovery from a security-related event.

22 CIPS units 1, 2, 4 and 5 are referred as Frame 6.
23 See https://sam.nrel.gov/.

A1.8.6 Generator outages

In the supply adequacy assessment, three types of generator outages were modelled:

- known planned outages – assumed to be timed in accordance with licensed generators' current asset management plans. These include necessary inspections, repairs, and refurbishments scheduled by each licensed generator to ensure long-term performance of their generator assets
- unknown planned outages – or maintenance rates, were included in the model as annual percentages. These rates were based on information sourced from licensed generators. In the model, there was a distinction between unknown and known planned outages. Unknown planned outages were only added if the total of hours in known planned outages was less than the assumed annual maintenance rate of a generator. Furthermore, while known planned outages have a defined schedule, unknown planned outages were dynamically assigned by the optimisation software to coincide with times of high-capacity reserves across each simulation year in the model
- unplanned outages – modelled in a probabilistic manner using Monte Carlo simulations.[24] The timing of these outages was randomly allocated based on the assumed outage rates. These rates were based on historical data and information provided by licensed generators. Where historical data was not available, or adequate, unplanned outage rates were used based on manufacturer's information for similar technology. The assumed unplanned outage rates in each power system are summarised in Table 6, Table 7 and Table 8 alongside the outage rates used in previous NTEORs.

Unplanned outage rates for the past three years, were calculated as:

$$\frac{total\ hours\ of\ unplanned\ outages}{total\ hours\ in\ operation + total\ hours\ of\ unplanned\ outages}$$

This resulted in outage rates that were more reflective of the likelihood a unit will be unavailable at a time when it was needed. Operational data from the three previous years was used to calculate the unplanned outage rates.

If, in any case, the rates calculated using historical data were not deemed to be reasonable, licensees were encouraged to contest the values during the consultation process and propose alternative values based on their expectation.

Table 6 shows the rates used in the model for the Darwin-Katherine system. Similar to the previous NTEOR assessment, some historical data does not reflect the expected outcome due to the presence of one-off events. This is particularly true for the units 1 and 6 at the CIPS in 2020-21 and units 8 and 9 at the CIPS in 2021-22. To calculate a more reasonable rate, AEMO ignored 2020-21 for CIPS units 1 and 6 and ignored 2021-22 for CIPS units 8 and 9 when calculating the rate for these units.

24 A total of 200 Monte Carlo iterations were modelled, with 200 POE10 and 200 POE50 iterations.

Table 6: Unplanned outages rates by unit in Darwin–Katherine

Unit	Unplanned outages rate used in 2020 NTEOR	Unplanned outages rate used in 2021 NTEOR	Unplanned outages rate used in 2022 NTEOR (%)
CIPS 1–6	4.3	3.7	5.4
CIPS 7	8.9	6.6	8.0
CIPS 8 and 9	2.9	2.6	3.4
CIPS 10	-[1]	1.3[2]	1.3[2]
Shoal Bay	2.0	3.3	6.2
HCPS	1.5[3]	1.5[3]	1.5[3]
Weddell power station (WPS) 1–3	5.6	2.9	3.5
KPS 1–3	12.4	12.4	7.6
KPS 4	7.7	7.7	10.3
PCPS gas turbine (GT) 1 and 2	2.5[3]	0.5[3]	0.5
PCPS steam turbine (ST) 1	2.0[3]	2.0[3]	2.7

1. Unit was not considered in 2020 NTEOR.
2. Based on GE's availability parameter for TM2500 generators[25]
3. Values provided by the licensee rather than being calculated with historical data.

The outage rates for Territory Generation's units in Alice Springs are shown in Table 7. Since the commissioning of units 5-14 at the OSPS, unplanned outages rates on these units has been very high. It would be unreasonable to assume that these units would continue to perform at these high rates. However, AEMO believes that the rate previously provided by the licensee is too low compared with what has been observed so far. To address this, an initial historical rate of 21.7% was applied in the first forecast year, and the rate was gradually reduced to the proposed 3.9% over three years. The proposed 3.9% outage rate is based on the historical data of the units with the same technology type. RGPS units are still expected to continue to have a high rate of unplanned outages, due to the units approaching end of life.

Table 7: Unplanned outages rates by unit in Alice Springs

Unit	Unplanned outages rate used in 2020 NTEOR	Unplanned outages rate used in 2021 NTEOR	Unplanned outages rate used in 2022 NTEOR (%)
OSPS 1–3	7.8	6.3	9.1
OSPS 5–14	1.0[1]	32.1 to 1.0[2]	21.7 to 3.9[2]
OSPS A	2.2	2.7	1.9
RGPS 3–9	44.4	44.1	53.8

1. Values provided by the licensee rather than being calculated with historical data.
2. Variable rate discussed above.

25 See https://www.ge.com/gas-power/products/gas-turbines/tm2500.

The outage rates for Tennant Creek are shown in Table 8. TCPS units 1 and 5 did not have a substantial sample size to calculate unplanned outage rates. AEMO has adopted the value used in the 2017-18 NTEOR, when these units were used more regularly and had a larger breadth of operational history to determine the expected rate. The unplanned outage rate of TCPS units 16 to 18 has been high during recent years. However, Territory Generation has suggested it is expected to be reduced in future years. In this case, AEMO have adopted the same value used in the 2021 NTEOR.

Table 8: Unplanned outages rates by unit in Tennant Creek

Unit	Unplanned outages rate used in 2020 NTEOR	Unplanned outages rate used in 2021 NTEOR	Unplanned outages rate used in 2022 NTEOR (%)
TCPS 1 and 5	-[1]	2.8	2.8
TCPS 10–15	0.5	1.1	2.1
TCPS 16–18	3.6	5.0	5.0[2]
TCPS 19–21	1.0[3]	4.2 to 1.0[4]	3.9

1. Not modelled in the 2020 NTEOR.
2. Values chosen to be consistent with the 2021 NTEOR.
3. Values provided by the participant rather than being calculated with historical data.
4. Variable rate.

A1.8.7 Generator auxiliaries

Generator auxiliaries refer to energy used within a power station and are expressed as a percentage of generation output during periods of full output. AEMO's modelling of generator capacity is on an 'as generated' basis and therefore includes electricity consumed within the power plants. To remain consistent with the definition of system demand documented in section A1.7.1, AEMO considered generator auxiliaries for generators not owned by Territory Generation and subsequently all Territory Generation units were modelled without any auxiliary load. Table 9 shows the modelled values used in the supply adequacy assessment. These values approximate different fixed and variables losses of each generating unit. Solar generators were assumed to have an auxiliary load rate of 0.2%, which aligns with the aggregated average rate for this technology as per the 2022 Inputs, Assumptions and Scenarios Report.[26]

Table 9: Non-zero generator Auxiliary Losses to be modelled[1]

Unit	Auxiliary loss
HCPS	4.0
Shoal Bay	3.0
PCPS GT1 and GT2	0.8
PCPS ST1	6.5
Solar	0.2

1 Territory Generation units' auxiliary losses are considered to be zero for modelling purposes.

26 See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

A1.9 Transmission and power system security

Although system security is generally not considered in supply adequacy assessments, some system security aspects of the Territory's three power systems may affect the dispatch availability and transmission capacity, so were therefore included in the modelling.

AEMO has not sought to analyse or test PWC System Control's operational assumptions and has simply implemented them in the supply adequacy model. As such, simplifications were made in the implementation to minimise computation and complexity, while ensuring fidelity for periods that impact the supply adequacy assessment.

Given the Territory's three power systems are all undergoing transition at various rates and stages, current and emerging power system security requirements can be challenging to fully ascertain and quantify over the outlook period. Currently, there are numerous documents, risk notifications and models that define and describe the security requirements for the three power systems. While PWC System Control's Secure System Guidelines[27] are intended to document the present requirements, there is sufficient evidence[28] to suggest that actual operating requirements are more onerous and prescriptive than have yet been documented.

AEMO has not assessed the appropriateness of current system security requirements with regard to risk aversion or cost, but simply sought to apply security requirements that most closely match the actual current operation of the power systems for modelling purposes. Any additional changes to security requirements to further minimise security risks during operation may increase the estimated supply adequacy risk.

Power system security requirements were implemented in the economic model as constraints. These constraints bind to various degrees, simulating feasible dispatch scenarios, particularly at the times of system stress most relevant to a supply adequacy assessment. In some cases, less onerous constraints were included predominantly for completeness where more onerous constraints were expected to bind more frequently in simulation.

A1.9.1 Reserves and inertia

AEMO modelled the minimum reserve requirements of each Territory power system and a minimum pre-contingent inertia requirement for the Darwin–Katherine and Alice Springs power systems.

The reserve requirements are based on PWC's Secure System Guidelines Version 4.2.[29] AEMO understands that PWC System Control will likely review the existing requirements during the outlook period and may determine they are no longer appropriate. However, with no new guideline at present, and given the changeable nature of PWC System Control's Risk Notifications, AEMO in most instances adopted the requirements present in the Secure System Guidelines Version, 4.2.

27 See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

28 PWC, Northern Territory Regulated Power Systems Biannual Report – January to June 2021. Internal operating scenarios spreadsheets.

29 See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

Based on advice previously provided by Territory Generation and PWC, both spinning and regulating reserve requirements may be breached in any power system in situations where meeting the reserve requirement would result in load shedding (or USE). However, for modelling purposes, it was assumed these requirements could not be breached simply to allow more solar PV dispatch.

The inertia requirement was based on the maximum rate of change of frequency (RoCoF) value to be withstood in each power system in the event of the largest single contingency of each system. This is described in more detail in the sections below.

A1.9.2 Regulating reserve and spinning reserve

Regulating reserve means the capacity of an available generating unit or units to regulate frequency to keep it within the defined normal operating limits, including time error correction.

Spinning reserve enables a power system to respond to a disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.[30]

This outlook considered the minimum regional figure specified in PWC System Control's Secure System Guidelines, Version 4.2 for regulating reserve, summarised in Table 10.

Table 10: Regulating reserve minimum requirement in the Northern Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	5.0
Alice Springs	2.0
Tennant Creek	0.5

PWC System Control's Secure System Guidelines determine that the minimum regulating reserve requirement is the larger of the regional figure and system load rate of change. This rate is a dynamic rate determined by the anticipated change of the overall output of all online machines over the region's specific duration. System load rate of change considers anticipated load changes, such as storms approaching populated areas.

The anticipated rate of change is determined by the power system controller, therefore AEMO adopted the minimum regional figure throughout the outlook period.

The Secure System Guidelines also determine the spinning reserves' minimum regional figure. However, PWC System Control has revised the minimum spinning reserves in all three power systems with risk notifications. The reasons for this include, but are not limited to, observed large and rapid fluctuations associated with the increased penetration of distributed PV, and changes following the Alice Springs system black in October 2019. While these notifications are temporary, AEMO believes some of the conditions may persist, and therefore the new levels set by these notifications may become permanent in the years to come, noting there may be other solutions.

The spinning reserve minimum requirements in Darwin-Katherine was increased to 37 MW during the daytime (from 30 MW), as suggested by stakeholders during the 2022 NTEOR Methodology and Assumptions consultation. The spinning reserve minimum requirements used in the 2022 NTEOR are summarised in Table 11.

30 PWC Secure System Guidelines, Version 4.2.

Table 11: Spinning reserve minimum requirement in the Northern Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	37 MW (day-time)
	25 MW (night-time)
Alice Springs	12 MW (day-time)
	7 MW (night-time)
Tennant Creek	0.8 MW

All regulating units (controllable variable load) may provide regulating and spinning reserve and the two reserve requirements are not mutually exclusive. That is, spare available capacity used to provide one reserve service may also be used to provide reserve to the other service.

The Secure System Guidelines mention that a contingency frequency control ancillary service (C-FCAS) will replace the current spinning reserve requirements in all three power systems. However, PWC System Control does not mention a changeover date in the document pending specific requirements of the C-FCAS policy to be established with system participants, such as the accreditation of machine C-FCAS provision and reference times for C-FCAS services. Given the uncertainty regarding these aspects of the C-FCAS implementation, and the lack of the necessary technical data to correctly implement generators' response to the C-FCAS, AEMO decided not to implement the C-FCAS in this year's assessment and chose to simply use the spinning reserve requirement.

To better model the evolving power system, consistent with the 2021 NTEOR, the Commission decided to exclude machine-specific additional spinning reserve operational requirements. These requirements are specified in the Secure System Guidelines and had been modelled in previous NTEORs. They determine dispatch conditions that are to be met at all times. However, given the expected changes in the Territory's power systems that aim to quantify the provision of essential system security services, the requirements are likely to become obsolete. Initial modelling tests without these requirements showed no material changes to forecast USE in any of the Territory's power systems.

A1.9.3 Treatment of reserve requirements under low reserve conditions

While reserve requirements are considered essential system services, based on advice provided by PWC System Control, in practice under some circumstances where no imminent risks to the power system are foreseeable, the reserve requirements may be relaxed to avoid USE.

Providing the form and level of the reserve requirements are appropriately determined and set by PWC System Control, AEMO notes that in not maintaining the reserve requirements in order to avoid USE to some consumers may cause the operation of the overall power system to be less secure, and at an increased risk of a major event, including a black system. These trade-offs need to be carefully managed.

To avoid exaggerating the risk to consumers, AEMO forecast expected USE both assuming the reserve requirements may be breached, and that they may not be breached. This allows decision-makers to understand both the reliability and power system security risks that may emerge under low reserve conditions.

A1.9.4 Rate of change of frequency and inertia requirement

Inertia, traditionally provided by the rotating mass of thermal synchronous generators, acts like a shock absorber in a power system and reduces its RoCoF following a contingency event, such as a generator or transmission line tripping, to give sufficient time for the system to respond to the contingency. Sufficient inertia is vital for system security.

Due to the likelihood of periods in the outlook with limited dispatched thermal generation (or other inertia providing technologies), and based on discussions with PWC System Control, AEMO assumed the minimum inertia requirements for the Darwin-Katherine and Alice Springs systems for the 2022 NTEOR to limit the RoCoF to secure levels.

The minimum inertia requirement is not additional capacity to that supplied to meet customer demand, rather it is a requirement to have a certain type of capacity online that can provide both inertia (or inertia services) and generation supply at the same time. It essentially sets a minimum level of synchronous rotating mass that must be online to ensure a secure system. However, AEMO notes this can also be offset by other RoCoF service technologies such as batteries providing fast frequency response.

As per the Secure System Guidelines, the minimum RoCoF level is required to ensure the orderly operation of the under-frequency load shedding and the over frequency generation shedding schemes, and to ensure RoCoF remains within the capabilities of the dispatched generation to prevent pole slipping (which can lead to cascading failure).

Based on recommendations from PWC System Control, the assumed pre-contingent minimum inertia requirement in each power system was set to keep RoCoF below 1.35 Hertz per second (Hz/s) after a single critical failure (a contingency as defined below). The Secure System Guidelines state this figure is only preliminary and further assessment will be completed to accurately determine the RoCoF limits for each power system; AEMO opted to use this figure in the absence of any alternative.

The contingencies considered in each system are, for:

- Darwin-Katherine – The greater of the largest individual unit output or the flow of the 132 kV transmission line into Channel Island. For modelling purposes, the inertia required was only enforced on the Darwin node of the Darwin-Katherine power system and not the Katherine or Manton, Batchelor, and Pine Creek nodes
- Alice Springs – The largest individual unit output.

AEMO worked with PWC System Control to determine pre-contingent levels of inertia that would maintain a RoCoF under 1.35 Hz/s for these contingencies, provided in Table 12. The requirements were modelled as variable values based on the formula expressed in the table. The model did not allow the minimum inertia requirement to be breached in order to dispatch additional large-scale solar PV capacity.

Table 12: Minimum inertia requirements

Power system	Minimum requirement (MWs)	Typical range[1]
Darwin-Katherine	Inertia requirement (MWs) = (Darwin contingency (MW) x system frequency)/(2 x RoCoF limit)	108 to 625 MWs
Alice Springs	Inertia requirement (MWs) = (Alice Springs contingency (MW) x system frequency)/(2 x RoCoF limit)	16 to 85 MWs
Tennant Creek	None	-

MW: megawatts; MWs: megawatt-seconds; RoCoF: rate of change of frequency
1 Based on the operational range observed in the 2018-19 NTEOR.

For the purpose of modelling, the thermal units that can provide inertia, and their respective individual contribution as provided by PWC System Control are listed in Table 13.

Table 13: Inertia contribution per unit

Power system	Units	Inertia contribution (MWs)
Darwin-Katherine	CIPS 1. 2. 4 and 5	214.0
	CIPS 6	145.9
	CIPS 7	79.4
	CIPS 8 and 9	102.4
	CIPS 10	28.3
	WPS 1–3	82.6
Alice Springs	RGPS 3–5	11.9
	RGPS 6–7	9.0
	RGPS 9	39.4
	OSPS 1–3	22.3
	OSPS A	14.7
	OSPS 5–14	6.9

PWC System Control advised that the inertia contribution of Territory Generation's BESS in Alice Springs has not been quantified. Therefore, the BESS was excluded from contributing to the inertia requirement for modelling purposes.

It is understood that Territory Generation's future Darwin BESS will likely be used to compensate for the loss of inertia in the system with the retirement of the Frame 6 generating units at the CIPS. Therefore, although the actual inertia contribution of this BESS is still to be determined, for the purpose of modelling, the Darwin BESS was considered to provide the same amount of inertia as CIPS units 1-5 when available (that is, 214.0 MWs). However, the BESS did not provide energy in the supply adequacy assessment.

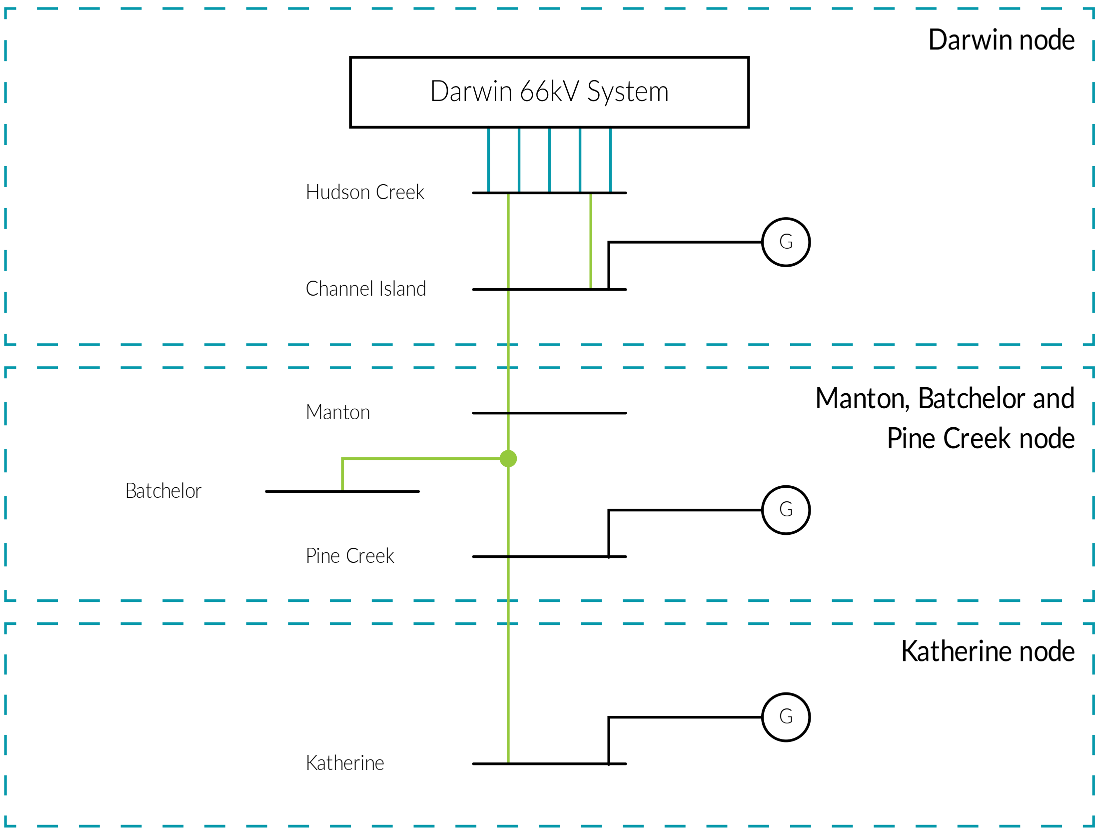
A1.9.5 Inter-regional limitations

The 2022 NTEOR supply adequacy assessment considered the Darwin–Katherine power system as three subregional nodes, as shown against the simplified single line diagram in Figure 42. Numerous limitations exist between the three nodes, constraining the ability of generation in one region to meet the consumer demands in another. These limitations include:

- thermal limitations on the transmission lines and transformers
- security limitations to ensure the secure operation of each subregion and the power system as a whole.

The thermal limit between the Darwin node and the Manton, Batchelor and Pine Creek node was assumed as the line design rating for the Manton 132 kV to Pine Creek 132 kV/T-off Batchelor 132 kV line, being 107 megavolt-amperes (MVA)[31] or approximately 105 MW. The thermal limit between Manton, Batchelor and Pine Creek node and the Katherine node was assumed as the rating for the 132/22 kV Katherine zone substation, being 28.8 MVA[32] or approximately 28 MW.

Figure 42: Darwin–Katherine single line diagram



31 Transmission and Distribution Planning Report., Appendix I, at https://www.powerwater.com.au/about/regulation/transmission-and-distribution-planning.

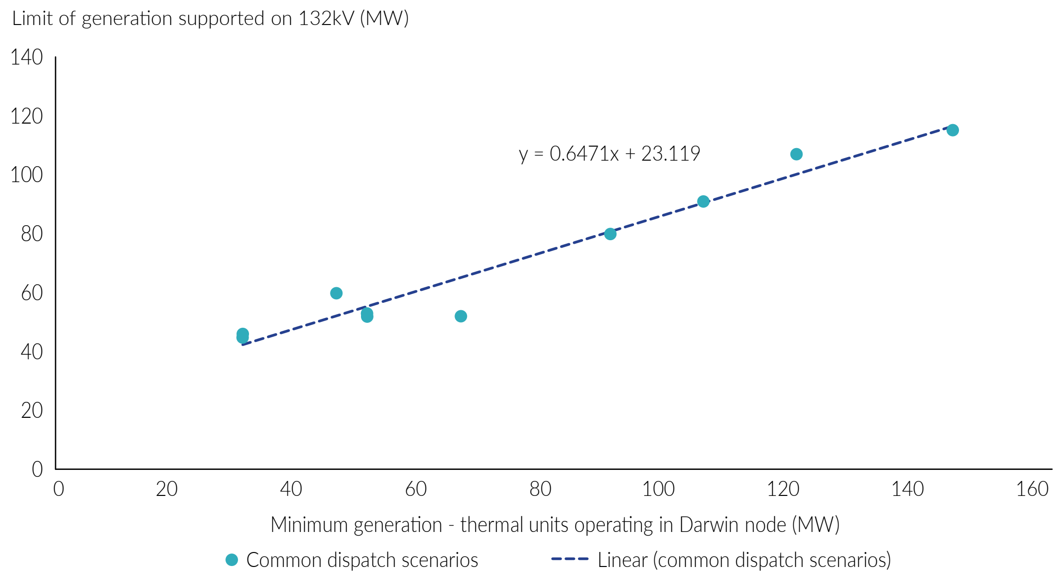
32 Transmission and Distribution Planning Report., Appendix K, at https://www.powerwater.com.au/about/regulation/transmission-and-distribution-planning.

Numerous power system security requirements apply to the lines in practice, however numerous dispatch scenarios were provided by PWC System Control that capture these requirements. These scenarios did not include every possible dispatch configuration but included a diverse range of secure dispatches based on actual operational dispatch cases that aim to maximise line throughput with the total system load varying from 100 MW to 400 MW.

While numerous security considerations were included in the dispatch scenarios, a very strong relationship could be identified between constraints imposed on the generation limit for all generation south of Channel Island, and the sum of the minimum stable generation output of all thermal units operating in the Darwin node.

The relationship implies that the constrained output of all generators south of Channel Island, considering the possibility of a single credible contingency on the line, can be expressed in MW as 23.1 + 0.65 * (sum minimum thermal generation in Darwin), as shown in Figure 43. When the Darwin BESS is installed, it is assumed to be equivalent to 10 MW of minimum thermal generation for the purposes of this calculation, or the equivalent of a permanent increase in line capacity of 6.5 MW. This is considered a similar provision of system services to the current Frame 6 machines.

Figure 43: 132 kV Darwin import limit relative to minimum stable of thermal generation operating in the Darwin node



All limits are summarised in Table 14.

Table 14: Limits between Darwin-Katherine nodes

Inter-regional limits	Thermal limit (towards Darwin)	Thermal limit (towards Katherine)	Security limit (towards Darwin)	Security limit (towards Katherine)
Manton to Channel Island	105 MW	105 MW	Nil	Nil
Katherine to Pine Creek	28 MW	28 MW	Nil	Nil
All generation south of Channel Island	Nil	Nil	23.1 + 0.65 x (sum minimum stable load for all operating thermal units in Darwin node) + 6.5 x (Darwin BESS operating)	Nil

A1.9.6 Transmission forced outages

Given the importance of the transmission lines between the Darwin–Katherine nodes for supply adequacy, the assessment included the probability of forced outages in the lines. In the recent history of major outages on the 132 kV Darwin–Katherine line, 43 incidents were found resulting from weather, operator error, or asset failure on the lines or related busbars. Outages observed that resulted in the islanding of Pine Creek and Katherine together were allocated to the Manton to Channel Island line, while outages that resulted in the separation of Katherine from the rest of the power system were allocated to the Katherine to Pine Creek line. The average attributes of these outages formed the assumptions in the model, as shown in Table 15.

Table 15: Transmission forced outage rates for lines between Darwin-Katherine nodes

Inter-regional line	Outage rate (%)	Average outage duration (hh:mm)
Manton to Channel Island	0.09	2:03
Katherine to Pine Creek	0.03	1:23

During a transmission line forced outage in the simulation the thermal limit was set to 0 MW, and all non-synchronous generation south of Channel Island were constrained off. During these periods, it was assumed that the system was able to operate securely, including the effective islanding of the Katherine, and Manton, Batchelor and Pine Creek nodes.

A1.9.7 Battery assumptions

For the 2022 NTEOR supply adequacy assessment, AEMO assumed no contribution to generation supply from large-scale batteries, including Territory Generation's Darwin BESS and BESS in Alice Springs, as it is understood they are not intended for this purpose. While Territory Generation's new Darwin BESS was not included as an energy provider in the supply adequacy assessment, it was considered as a provider of RoCoF services and other system security requirements in the modelling. Though not directly providing energy, it optimised the dispatch and transmission capabilities, indirectly contributing to improving supply adequacy in the Darwin–Katherine power system.

A1.9.8 Supply adequacy methodology

AEMO used a probabilistic approach to assess the reliability of the Territory's power systems. Hourly market modelling simulations across 400 Monte Carlo iterations were used to identify the probability of available capacity being insufficient to meet demand given the likelihood of coincident outages across the generation portfolio in each system. Planned and unplanned outages were critical inputs to this assessment.

The Monte Carlo iterations were split into 200 POE10, 200 POE50 and zero POE90 iterations. A weighted average was used to reconcile the different USE levels under each POE scenarios to achieve the expected results.

AEMO used weightings of POE10: 30.4%, POE50: 39.2%, POE90: 30.4%, where USE under POE90 demand conditions is assumed to be zero, consistent with the AEMO NEM ESOO methodology.[33] Weighted USE was then compared with the reliability standard of 0.002% used in the NEM simply for reference.[34]

The generation adequacy assessment investigates whether additional generation capacity, or other technologies, are required to deliver the level of reliability comparable with the reliability standard in the NEM, which is that the maximum expected USE should not exceed 0.002% of total energy demand in a given region and financial year.[35]

While the Northern Territory Government has published a consultation paper that proposes the Territory will use a different form of reliability standard to the NEM and WEM,[36] there remains uncertainty about the final form and level of reliability standard in the Territory. Accordingly, the reliability assessment in the 2022 NTEOR was calculated as USE only.

33 At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/esoo-and-reliability-forecast-methodology-document-2022.pdf?la=en

34 The reliability standard used in the NEM and the Western Australia Wholesale Electricity Market (WEM) is 0.002% USE. The WEM has a second standard that requires there to be sufficient available capacity to meet peak demand plus either the maximum capacity of the largest generating unit or 7.6% of peak demand.

35 In the NEM this covers the interconnected electricity network (excluding off-grid and islanded systems) in Queensland, New South Wales, Victoria, South Australia and Tasmania. For the purpose of this report, the NEM's existing 0.002% reliability standard is used for comparison. The 'interim reliability measure,' announced on 20 March 2020 by the Energy Security Board, is not used in this report.

36 See https://industry.nt.gov.au/__data/assets/pdf_file/0007/968209/ntemprp-design-capacity-mechanism-consultation-paper.pdf.

Appendix A2: Supply details

A2.1 Existing and committed generator units

The list of existing and committed generators in the Territory considered in this outlook is provided in Table 16 to 18. This information is based on data provided by licensed generators and the Commission.

Table 16: Existing and committed generator units in Darwin-Katherine

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
CIPS 1	31.6	30.0	Gas	1/01/1986	31/12/2026	37
CIPS 2	31.6	30.0	Gas	1/01/1986	31/12/2026	37
CIPS 4	31.6	30.0	Gas	1/01/1986	31/12/2027	37
CIPS 5	31.6	30.0	Gas	1/01/1986	31/12/2027	37
CIPS 6	32.0	30.4	Waste heat	1/01/1987	31/12/2027	36
CIPS 7	36.0	34.2	Gas	1/01/2000	31/12/2029	23
CIPS 8	42.0	39.9	Gas	1/01/2011	n/a	12
CIPS 9	42.0	39.9	Gas	1/01/2011	n/a	12
CIPS 10	23.6	22.2	Gas	30/12/2024	n/a	-
SBPS	1.1	1.1	Landfill gas	1/08/2005	n/a	17
HCPS	14.5	14.5	Gas	01/04/2024	n/a	-
WPS 1	34.0	32.2	Gas	1/02/2008	n/a	15
WPS 2	34.0	32.3	Gas	1/11/2008	n/a	14
WPS 3	34.0	32.3	Gas	1/03/2014	n/a	9
KPS 1	8.5	7.65	Gas	1/01/1987	n/a	36
KPS 2	7.5	6.8	Gas	1/01/1987	n/a	36
KPS 3	8.5	7.7	Gas	1/01/1987	n/a	36
KPS 4	12.0	10.8	Gas	1/07/2012	n/a	10
PCPS GT1	10.2	9.7	Gas	1/07/2018	n/a	4
PCPS GT2	10.2	9.7	Gas	1/07/2018	n/a	4
PCPS ST1	6.0	5.8	Waste heat	1/06/1996	n/a	27
Darwin RAAF	3.2	2.9	Solar	05/09/2023	n/a	-
Robertson Barracks	10.0	8.9	Solar	28/09/2023	n/a	-
Batchelor 2	10.0	10.0	Solar	30/12/2023	n/a	-
BSPS	10.0	10.0	Solar	31/12/2023	n/a	-
KSPS	25.0	25.0	Solar	31/12/2023	n/a	-
MSPS	10.0	10.0	Solar	31/12/2023	n/a	-

Table 17: Existing and committed generator units in Alice Springs

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
OSPS 1	10.7	10.2	Gas	1/10/2011	n/a	11
OSPS 2	10.7	10.2	Gas	1/10/2011	n/a	11
OSPS 3	10.7	10.2	Gas	1/11/2011	n/a	11
OSPS 5	4.4	4.1	Gas	1/01/2019	n/a	4
OSPS 6	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 7	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 8	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 9	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 10	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 11	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 12	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 13	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS 14	4.4	4.1	Gas	1/03/2019	n/a	4
OSPS A	3.9	3.7	Gas	1/01/2004	n/a	19
RGPS 3	4.2	4	Gas	1/01/1973	31/12/2025	50
RGPS 4	4.2	4	Gas	1/01/1973	31/12/2025	50
RGPS 5	4.2	4	Gas	1/01/1975	31/12/2025	48
RGPS 6	5.5	5.2	Gas	1/01/1978	31/12/2025	45
RGPS 7	5.5	5.2	Gas	1/01/1981	31/12/2025	42
RGPS 9	13.5	12.8	Gas	1/11/1987	31/12/2025	35
Uterne Solar	3.9	3.9	Solar	1/08/2015	n/a	7

Table 18: Existing and committed generator units in Tennant Creek

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
TCPS 1	1.2	1.1	Gas	No data	31/12/2023	-
TCPS 5	1.2	1.1	Gas	No data	31/12/2023	-
TCPS 10	1	0.9	Gas	1/01/1999	n/a	24
TCPS 11	1	0.9	Gas	1/01/1999	n/a	24
TCPS 12	1	0.9	Gas	1/01/1999	n/a	24
TCPS 13	1	0.9	Gas	1/01/1999	n/a	24
TCPS 14	1	0.9	Gas	1/01/1999	n/a	24
TCPS 15	3.9	3.7	Gas	1/01/2004	n/a	19
TCPS 16	1.5	1.4	Diesel	1/02/2008	n/a	15
TCPS 17	1.6	1.5	Diesel	14/12/2018	n/a	4
TCPS 18	1.6	1.5	Diesel	14/12/2018	n/a	4
TCPS 19	2.0	1.9	Gas	14/12/2018	n/a	4
TCPS 20	2.2	2.1	Gas	14/12/2018	n/a	4
TCPS 21	2.2	2.1	Gas	14/12/2018	n/a	4

A2.2 Projected unserved energy

The following tables show the forecast USE for each Territory region and subregional node.

Table 19: Projected unserved energy in the Darwin-Katherine power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0000	0.0002	0.0008	0.0010
2024-25	0.0000	0.0000	0.0001	0.0002
2025-26	0.0000	0.0001	0.0000	0.0001
2026-27	0.0000	0.0003	0.0003	0.0006
2027-28	0.0056	0.0072	0.0207	0.0335
2028-29	0.0234	0.0727	0.0963	0.1924
2029-30	0.0566	0.0656	0.1335	0.2558
2030-31	0.1578	0.2242	0.2887	0.6707
2031-32	0.1624	0.2226	0.2871	0.6721

Table 20: Projected unserved energy in the Darwin node (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0000	0.0002	0.0008	0.0010
2024-25	0.0000	0.0000	0.0002	0.0002
2025-26	0.0000	0.0001	0.0000	0.0001
2026-27	0.0000	0.0003	0.0003	0.0007
2027-28	0.0063	0.0080	0.0234	0.0378
2028-29	0.0259	0.0811	0.1094	0.2164
2029-30	0.0634	0.0729	0.1518	0.2882
2030-31	0.1761	0.2523	0.3277	0.7562
2031-32	0.1813	0.2498	0.3262	0.7573

Table 21: Projected unserved energy in the Manton, Batchelor Pine Creek node (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0000	0.0000	0.0000	0.0000
2024-25	0.0000	0.0001	0.0000	0.0001
2025-26	0.0000	0.0000	0.0000	0.0000
2026-27	0.0000	0.0000	0.0003	0.0003
2027-28	0.0000	0.0001	0.0004	0.0006
2028-29	0.0000	0.0014	0.0002	0.0016
2029-30	0.0000	0.0015	0.0004	0.0019
2030-31	0.0000	0.0018	0.0014	0.0031
2031-32	0.0000	0.0028	0.0000	0.0028

Table 22: Projected unserved energy in the Katherine node (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0001	0.0001	0.0005	0.0006
2024-25	0.0001	0.0001	0.0000	0.0002
2025-26	0.0002	0.0002	0.0000	0.0003
2026-27	0.0002	0.0001	0.0001	0.0003
2027-28	0.0006	0.0010	0.0009	0.0025
2028-29	0.0062	0.0124	0.0000	0.0186
2029-30	0.0071	0.0135	0.0000	0.0206
2030-31	0.0263	0.0174	0.0000	0.0437
2030-31	0.0261	0.0231	0.0000	0.0492

Table 23: Projected unserved energy in the Alice Springs power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0032	0.0103	0.0221	0.0356
2024-25	0.0010	0.0027	0.0086	0.0123
2025-26	0.0003	0.0031	0.0050	0.0085
2026-27	0.0006	0.0021	0.0173	0.0199
2027-28	0.0005	0.0006	0.0072	0.0083
2028-29	0.0005	0.0005	0.0042	0.0052
2029-30	0.0005	0.0035	0.0081	0.0121
2030-31	0.0005	0.0006	0.0039	0.0049
2031-32	0.0006	0.0003	0.0040	0.0049

Table 24: Projected unserved energy in the Tennant Creek power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2023-24	0.0000	0.0000	0.0000	0.0000
2024-25	0.0000	0.0000	0.0000	0.0000
2025-26	0.0000	0.0000	0.0000	0.0000
2026-27	0.0000	0.0000	0.0000	0.0000
2027-28	0.0000	0.0000	0.0000	0.0000
2028-29	0.0000	0.0000	0.0000	0.0000
2029-30	0.0000	0.0000	0.00002	0.00003
2030-31	0.0000	0.0000	0.00002	0.00002
2031-32	0.0000	0.0000	0.00002	0.00002

Appendix A3: Forecasting performance

AEMO has prepared this forecasting performance assessment to determine the accuracy of the consumption and demand forecasts prepared by AEMO for the 2021 NTEOR. The performance assessment helps inform forecast improvements and build confidence in the forecasts produced. As part of this process, AEMO reviews and refines model inputs, assumptions and methodology.

A3.1 Annual system consumption

Table 25 compares forecast and actual annual system consumption for each of the Territory's power systems or nodes in 2021-22.

Table 25: Comparison between forecast and actual annual system consumption for 2021-22

Power system	2021-22 AEMO forecast (GWh)	2021-22 actual (GWh)	Difference (%)
Darwin-Katherine	1465.3	1465.3	-5.2
Darwin	1318.9	1392.7	-5.3
Manton, Batchelor and Pine Creek	22.1	20.8	6.3
Katherine	124.4	132.2	-5.9
Alice Springs	202.1	196.8	2.7
Tennant Creek	29.9	30.8	-2.9

The forecast system consumption value for the Darwin-Katherine power system in 2021-22 was 5.2% lower than the observed value and was outside of the acceptable tolerance of difference of ±3%. The majority of this difference is attributed to the forecast system consumption value for the Darwin node being 5.3% lower than the observed value. This was due to a combination of distributed PV system uptake being lower than forecast and hotter weather conditions in Darwin over 2021-22.

Over this period, the total installed capacity of distributed PV system in the Darwin node increased by 7.58 MW (2020-21 actual: 82.39 MW, 2021-22 actual: 89.97 MW) which was lower than the expected 11.74 MW increase (2021-22 forecast: 94.13 MW).

In addition, the Darwin region experienced hotter weather conditions in 2021-22 compared with past years. 2021-22 had the highest number of days in recent history where the maximum daily temperature exceeded 32°C at 275 days, which was 78 more days than 2020-21 (2021-22: 275, 2020-21: 197, 2019-20: 244, 2018-19: 232, 2017-18: 236). Hotter weather conditions were also experienced in Katherine which resulted in the forecast system consumption value in 2021-22 being lower than the observed value by 5.9%. There were 60 more days in 2021-22 where the maximum daily temperature exceeded 35°C compared with 2020-21 (2021-22: 206, 2020-21: 146, 2019-20: 195, 2018-19: 172, 2017-18: 159). The forecast system consumption value for the Manton, Batchelor, and Pine Creek node was 6.3% higher than the observed value which can be partially attributed to lower than typical consumption from significant loads in the node.

The forecast annual system consumption for the Alice Springs power system was 2.7% higher than the observed value. This is within the acceptable tolerance of difference of ±3%.

The forecast annual system consumption for the Tennant Creek power system was 2.9% lower than the observed value. This is within the acceptable tolerance of difference of ±3%.

A3.2 Maximum demand

Table 26 compares forecast and actual maximum system demand for each Territory power system or node in 2021-22.

The actual maximum system demand in the Darwin node was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 0.18% higher than the actual and judged by AEMO to be reasonable based on the conditions at the time.

The actual maximum system demand in the Katherine node was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 3.68% higher than the actual and judged by AEMO to be reasonable based on the conditions at the time.

The actual maximum system demand in the Manton, Batchelor, and Pine Creek node fell below the 90% POE forecast. The Manton, Batchelor and Pine Creek node is relatively small in comparison to the Darwin and Katherine nodes. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. Therefore, the actual maximum system demand fell outside the desired POE forecast band. This year's forecast builds on these observations to ensure better alignment with current demand level.

The actual maximum system demand in the Alice Springs power system was below the 90% POE forecast. The 90% POE forecast was 2.27% higher than the actual. This over-forecast was partly due to an atypical drop in industrial load of approximately 1.6 MW at time of maximum system demand in 2021-22. Accounting for this, the forecast was judged by AEMO to be reasonable.

The actual maximum system demand in the Tennant Creek power system was below the 90% POE forecast. The 90% POE forecast was 4.74% higher than the actual. The higher forecast was due to the expectation that the NGP infrastructure would be drawing power (0.751 MW) from the system during summer, which did not occur.

Table 26: Comparison between forecast and actual maximum for 2020-21

	2021-22 forecast (MW)					
Power system	POE90	POE50	POE10	2021-22 actual (MW)	Actual timestamp	Actual dry-bulb temperature (°C)
Darwin	240.54	247.15	256.25	255.8	Wednesday, 15 December 2021 18:30	31.8
Katherine	27.45	28.67	29.88	28.82	Tuesday, 19 October 2021 15:00	38.1
Manton, Batchelor, Pine Creek	4.84	5.17	5.59	4.79	Thursday, 21 October 2021 16:00	40
Alice Springs	49.66	51.96	54.98	48.56	Friday, 14 January 2022 16:00	39.7
Tennant Creek	7.52	7.94	8.53	7.18	Wednesday, 15 December 2021 14:30	41.9

A3.3 Minimum demand

Table 27 compares forecast and actual minimum system demand for each Territory power system or node in 2021-22.

The actual minimum system demand in the Darwin node was between the 50% POE and 10% POE forecast levels. The 50% POE forecast was 2.54% lower than the actual and judged by AEMO to be reasonable.

The actual minimum system demand in the Katherine node was 1.34% above the 10% POE forecast. This under forecast can be attributed in part to the underestimation of industrial load at time of minimum system demand in 2021-22 by 1.1 MW. Accounting for this, the forecast was judged by AEMO to be reasonable.

The actual minimum system demand in the Manton, Batchelor and Pine Creek node was between the 50% POE and 10% POE forecast levels. The 50% POE forecast was 5.38% lower than the actual and judged by AEMO to be reasonable considering the conditions at the time.

The actual minimum system demand in the Alice Springs power system was between the 50% POE and 10% POE forecast levels. The 50% POE forecast was 5.14% lower than the actual and judged by AEMO to be reasonable.

The actual minimum system demand in the Tennant Creek power system was above the 10% POE forecast. The 10% POE forecast was 19.26% higher than the actual. The Tennant Creek power system is relatively small in comparison to the other two power systems in the Territory. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. Therefore, although the actual minimum system demand fell outside the desired POE forecast band, the forecast was judged by AEMO to be reasonable.

Table 27: Comparison between forecast and actual minimum system demand for 2020-21

	2021-22 forecast (MW)					
Power system	POE90	POE50	POE10	2021-22 actual (MW)	Actual timestamp	Actual dry-bulb temperature (°C)
Darwin	58.53	65.69	73.58	67.4	Saturday, 11 June 2022 12:00	26.3
Katherine	5.63	6.15	6.62	6.71	Sunday, 22 May 2022 09:00	27.0
Manton, Batchelor, Pine Creek	0.71	0.88	1.04	0.93	Saturday, 11 June 2022 11:30	23.4
Alice Springs	6.63	7.75	8.73	8.17	Sunday, 14 November 2021 10:00	21.8
Tennant Creek	1.07	1.21	1.3	1.61	Tuesday, 7 September 2021 12:30	23.2

Data quality issues play a bigger role when forecasting minimum system demand than for maximum system demand, because network outages can reduce minimums by shedding load yet do not drive seasonal maxima. AEMO has made every effort to ensure the quality of the data used through information provided from participants.

Appendix A4: Glossary

ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
Batchelor 2	Batchelor 2 Solar Farm power station
BESS	battery energy storage system
Block load	large industrial load
BOM	Bureau of Meteorology
BSPS	Batchelor Solar Farm power station
C-FCAS	contingency frequency control ancillary services
CIPS	Channel Island power station
Commission	Utilities Commission of the Northern Territory
DER	distributed energy resources
Distributed PV	residential and commercial rooftop solar PV systems
DSP	demand side participation
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
FFP	fixed flat plate
FiT	feed-in-tariff
GSP	gross state product
GT	gas turbine
GWh	gigawatt hour, 1GW = 1 billion watts
HCPS	Hudson Creek power station
Hz/s	hertz per second
JDFPG	Joint Defence Facility Pine Gap
KPS	Katherine power station
KSPS	Katherine Solar power station
kV	Kilovolt, 1 kV = 1 thousand volts
kW	kilowatt, 1 kW = 1 thousand watts
LNG	liquefied natural gas
MSPS	Manton Solar Farm power station
MVA	megavolt-amperes
MW	megawatt, 1MW = 1 million watts
MWs	megawatt seconds
NEM	National Electricity Market
NTEOR	Northern Territory Electricity Outlook Report
OPSO	Operational demand as sent out
OSPS	Owen Springs power station
Outlook period	1 July 2022 to 30 June 2032
POE	probability of exceedance

Power systems	Darwin-Katherine, Alice Springs and Tennant Creek power systems
PWC	Power and Water Corporation
PV	photovoltaic
RAAF	Royal Australian Air Force
RGPS	Ron Goodin power station
RoCoF	rate of change of frequency
SAM	System Advisor Model
SAT	single axis tracking
Season year	year ending 31 August
ST	steam turbine
TCPS	Tennant Creek power station
USE	unserved energy
VPP	virtual power plant
WEM	West Australian Wholesale Electricity Market
WPS	Weddell power station