UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Northern Territory Electricity Outlook Report

2021

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Disclaimer

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 2021 NTEOR presents electricity consumption, maximum and minimum demand, and generation adequacy forecasts for the Territory's power systems over the 10-year outlook period from 2021-22 to 2030-31 (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 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 power systems, or subregions within the power systems
- 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, investors and electricity consumers by providing forecasts of prospective trends in system demand and supply reliability to identify challenges, gaps or opportunities.

The 2021 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*. Accordingly, the Commission supports the analysis, conclusions and recommendations made on its behalf by AEMO.

While 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, 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 2021 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)[1] should not exceed 0.002% of total electricity consumption in a NEM region in any financial year.[2]

AEMO deployed a methodology similar to that used in previous years, although it 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.

This year the Darwin-Katherine power system was split into three subregional nodes (nodes) for modelling purposes. By modelling each node separately, the NTEOR can better identify challenges and opportunities in each subregion in addition to the broader power system analysis. Discussion regarding this approach is included in Appendix A1.

Following feedback received during consultation, and for the first time, this NTEOR includes consideration of behind-the-meter battery storage systems and electric vehicles (EVs). Appendix A1 provides more information regarding how behind-the-meter battery storage systems and EVs were incorporated into the forecast of annual electricity consumption, and maximum and minimum demand.

1 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.

2 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. On 20 March 2020, the Energy Security Board announced interim reliability measures related to an out-of-market capacity reserve and an adjustment to the Retailer Reliability Obligation triggers. Both measures will be based on AEMO's forecast of USE exceeding 0.0006% of total energy consumption. For the purpose of this report, the existing 0.002% reliability standard is used for comparison.

Key findings and recommendations

The Territory's electricity supply industry is undergoing a rapid transformation. This is primarily due to the displacement of synchronous gas and diesel generation by asynchronous distributed solar photovoltaic (PV) systems on residential and commercial premises (distributed PV) and large-scale solar PV systems that are in the process of connecting to the Darwin-Katherine network. As the Commission has consistently acknowledged, this transformation is particularly challenging given the Territory's power systems are small, isolated, lacking in diversity of renewable energy technologies and without supporting market frameworks.

The 2020 NTEOR made it clear urgent attention was needed to mitigate emerging risks and ultimately protect the long-term interests of Territory electricity consumers.

Following publication of the 2020 NTEOR, the Territory Government progressed and publicly released its Darwin-Katherine electricity system plan. Further, Territory Generation, the government owned generator, provided the Commission with its draft Darwin Katherine fleet transition plan business case, which includes details on its current generation and battery energy storage system (BESS) and proposed projects over the outlook period.

The Darwin-Katherine electricity system plan, among other things, acknowledges there are challenges with transitioning to renewable energy and sets out focus areas that government considers will support 50% renewable energy by 2030. Territory Generation's draft plans could also help address the security and reliability challenges. However, plans that are not fully funded or that are particularly ambitious in terms of technology, complexity and timing, do not provide sufficient assurance to the Commission that the emerging challenges (and opportunities) will be appropriately met, including in terms of efficiency, cost and risk.

As such, one year later, and despite increased government and industry activity, particularly in terms of planning, the Commission considers limited progress has been made and the three key overarching themes or 'big risks' identified in the 2020 NTEOR remain valid. These are:

- Territory Generation's planned retirement of six large generators at the Channel Island power station (CIPS) and three generators at the Katherine power station (KPS)
- the need for government to accelerate the electricity market reform program, particularly in relation to essential system services
- the forecast capacity shortfall to meet system security requirements in Darwin-Katherine and Alice Springs.

The 2021 NTEOR is based on an assessment of a business-as-usual scenario, which includes all committed projects that were approved and funded as at January 2022. It excludes the Territory Government's Darwin-Katherine electricity system plan and Territory Generation's unfunded plans and projects.

The Commission's assessment forecasts system security challenges as a result of falling minimum demand, primarily as a result of increasing household and commercial distributed PV systems. Licensees have advised these challenges are already apparent in Alice Springs, and they are forecast to start as early as 2023-24 in Darwin-Katherine. While not factored into the 2021 NTEOR modelling due to the timing, the Commission acknowledges government's recent decision to progressively remove the premium feed-in tariff Jacana Energy pays to some of its customers may encourage more efficient consumer behaviour, and may in turn delay system security issues associated with minimum demand to some extent.

Based on the business-as-usual scenario, shortfalls are also forecast for generation capacity and essential system services, leading to an increased risk of power outages. These shortfalls are expected as early as 2026-27 and 2027-28 in Alice Springs and Darwin-Katherine, respectively. This signals the need for urgent investment in new generation, storage and or demand response, noting the Darwin-Katherine forecast assumes the end-of-life generators at the CIPS remain serviceable and available until that date.

As stated in previous years' reports, there is a need for government to accelerate its electricity market reform program, particularly in relation to essential system services. While PWC System Control's current approach to managing system security challenges may be necessary given the circumstances, its approach of directing generators to run to provide additional spinning reserve or other services, when they would otherwise not, comes at an additional cost to Territory Generation, and thus Territory electricity consumers and taxpayers. At the same time, private industry remains effectively locked out of providing essential system services, noting government has still not made its final position on the competitive provision of essential system services known. The Commission maintains its view that although direct government investment may be needed for some aspects of the electricity market given the Territory's small size and the urgency of the current reliability and security challenges, industry's involvement is vital to encourage innovation, achieve the changes needed at least cost and share the risk.

The Commission is hopeful the various plans mentioned above indicate momentum is building and appropriate government and industry commitment and action is in train. Without this, delays in meeting the emerging challenges and opportunities mean less time to respond, which may increase risks and costs, and may ultimately negatively impact Territory electricity consumers and taxpayers.

The next section sets out the specific 2021 NTEOR findings by power system.

Darwin-Katherine

- System electricity consumption further decreased in 2020-21 partly due to increases in distributed PV, that is, residential and commercial rooftop solar PV systems. This trend is forecast to continue over the outlook period, although some new industrial loads are forecast to reduce the rate of decline.
- System maximum demand is forecast to rise in the short term due to the connection of new large industrial loads (block loads), then remain steady, as the timing of maximum demand is expected to occur after sunset.
- System minimum demand is forecast to decline to below 20 megawatts (MW) by the end of the outlook period, due to increasing penetration of distributed PV. This will likely cause system security implications without further measures to mitigate this risk.

- A number of units at the CIPS and KPS are scheduled to retire from 2026-27. These retirements are partially offset by currently committed[3] generation and battery investments, including six solar generators, the new gas-fired Channel Island generator (CIPS 10) and Hudson Creek power station (HCPS), and the Darwin BESS.
- As a result of the retirements, USE is forecast to increase, significantly exceeding the assumed reliability standard from 2026-27. This signals the need for additional investment in new generation, storage, and or demand response, or the deferral of scheduled generator retirements.
- While significant USE is forecast, the reliability outlook has improved in comparison with the forecast last year. This is attributable to stronger forecast uptake of distributed PV, and the newly committed CIPS 10 unit.
- 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

- System consumption has been declining since 2016-17. However, system consumption is forecast to increase following the connection of the Joint Defence Facility Pine Gap (JDFPG) to the Alice Spring network in 2022-23, before an expected decline for the remainder of the outlook period.
- Annual maximum demand is forecast to remain flat following the JDFPG connection, while minimum demand is forecast to decrease in line with the uptake of distributed PV.
- Expected USE is forecast to be above the assumed reliability standard in the early years of the outlook period while units at Owen Springs power station (OSPS) are assumed to continue to experience high outage rates in the near term, highlighting possible reliability and operability challenges.
- Expected USE is then forecast to be above the Commission's adopted reliability standard from 2026-27, after the assumed retirement of Ron Goodin power station (RGPS).
- Although the RGPS units are at the end of their life cycle, they are still forecast to provide reliability improvements while serving as back-up generators and reserve-providing units until their retirement. However, this added power system reliability and security comes at an increased cost to Territory Generation, and thus Territory electricity consumers and taxpayers.

3 Committed projects are those the Commission considers have demonstrated sufficient development progress and are highly likely to proceed.

4 The Commission has not sought to determine whether the plans are feasible or the best solutions to address the forecast reliability risks over the outlook period, including from technology, regulatory, energy security or cost perspectives as it is outside the scope of this report.

Tennant Creek

- 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.
- AEMO notes the power system may still be susceptible to other outages over the outlook period due to system security risks and operational challenges not considered in this reliability assessment.

Contents

1 Darwin-Katherine outlook

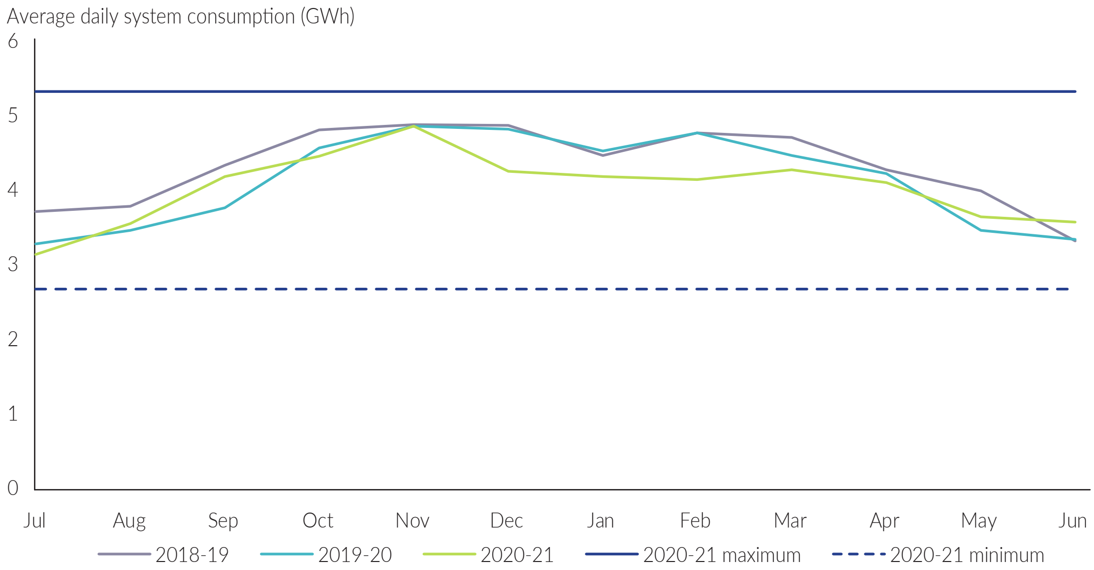
Annual electricity consumption

Electricity consumption observed in 2020-21

In 2020-21, total annual electricity system consumption[5] in the Darwin-Katherine power system was 1,465 gigawatt hours (GWh).[6] This was 2.7% lower than the system consumption recorded in 2019-20. This reduction can be attributed in part to the continued growth of distributed PV. The installed capacity of distributed PV increased from 77.9 MW to 88.0 MW over the 2020-21 financial year.

Figure 1 shows average daily system consumption by month over the past three financial years for the Darwin-Katherine power system. Average daily system consumption in 2020-21 was 4.0 GWh, and maximum and minimum daily consumption were 5.3 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, 2018-19 to 2020-21



Recent history and forecast per Darwin-Katherine subregional node

Annual electricity system consumption for the Darwin-Katherine power system has declined since 2016-17. This trend has been driven by increases in distributed PV and several industrial loads disconnecting from the network, including liquefied natural gas (LNG) infrastructure and mining loads.

Consumption is forecast to decline over the outlook period, a trend which is consistent with the last five years. The forecast does not consider any further large loads disconnecting from the power system. Several temporary and permanent block loads

5 As defined in Appendix A1.6.

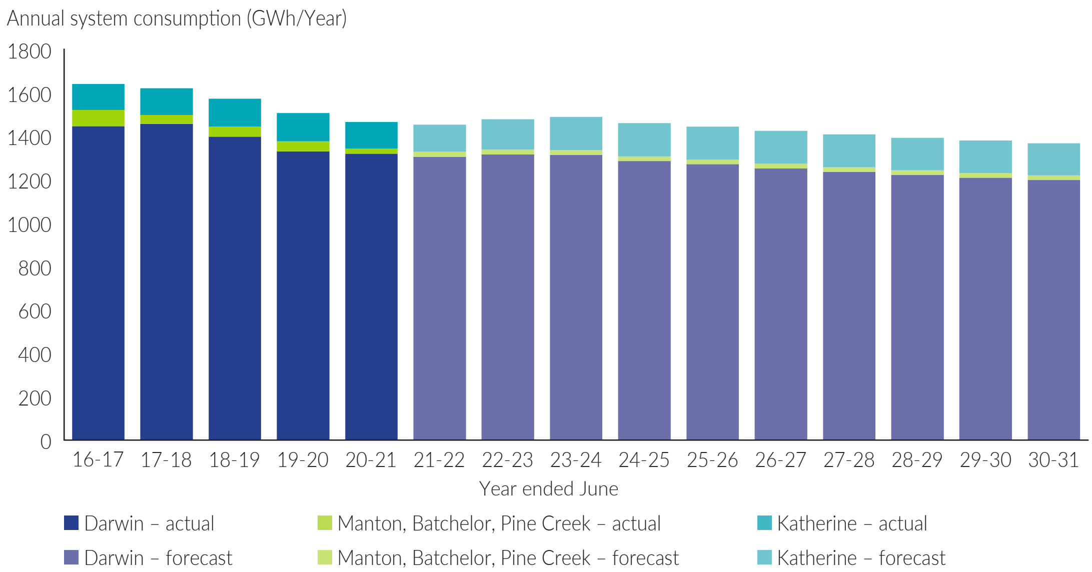
6 Total annual daily system consumption may vary from the 2020-21 Northern Territory Power System Performance Review due to differences in the calculation methodology and or rounding.

(see Appendix A1.6.5, Table 2 for details on block load assumptions) have largely offset the effects of projected growth in distributed PV and other long-term drivers in the initial three years of the forecast. From 2024-25, the decrease in forecast annual system consumption is driven by the projected growth of distributed PV and an overall declining trend observed from history.

The closure of mining loads has most substantially impacted consumption in the Manton, Batchelor and Pine Creek node in the past five years. Forecast consumption in the Katherine node includes the largest proportional increase driven by forecast new block load connections.

Figure 2 shows historical and forecast annual system consumption for the Darwin-Katherine power system.

Figure 2: Historical and forecast annual system consumption for Darwin-Katherine by year, 2016-17 to 2030-31



Maximum demand

Maximum demand forecasts for the Darwin-Katherine power system are reported by node.

Darwin forecast

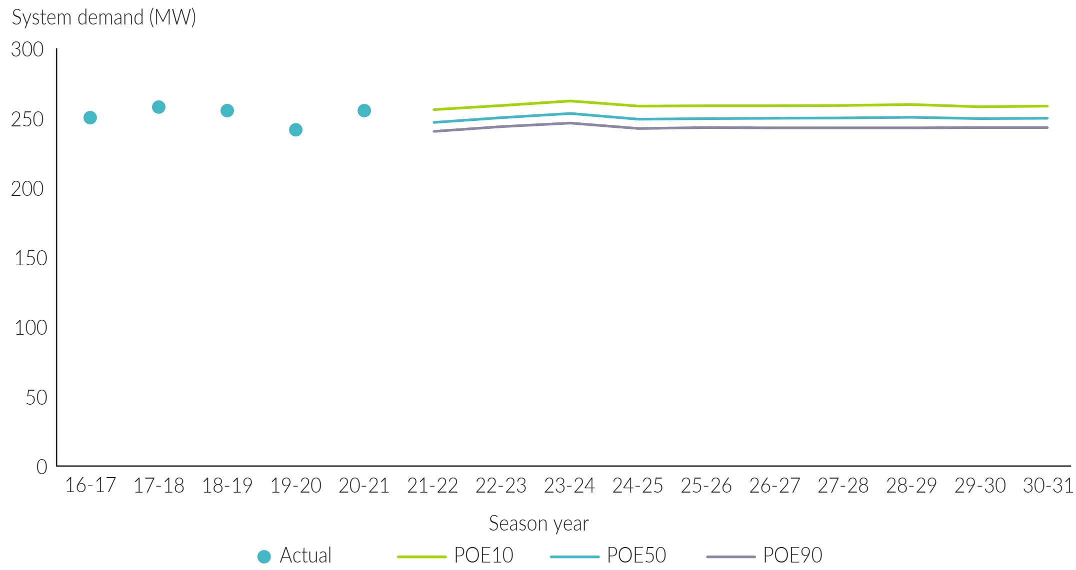
Figure 3 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different probability of exceedance (POE)[7] levels in the Darwin node from 2016-17 to 2030-31.

The 2020-21 maximum system demand of 255 MW occurred during the wet season and was 14 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 cooling (or air conditioning).

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.

Maximum system demand is forecast to slightly 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 increasing penetration of distributed PV, with the 2020-21 maximum system demand occurring at 19:00. Maximum system demand is forecast to remain in the wet season and to occur between 18:30 and 20:00 over the outlook period.

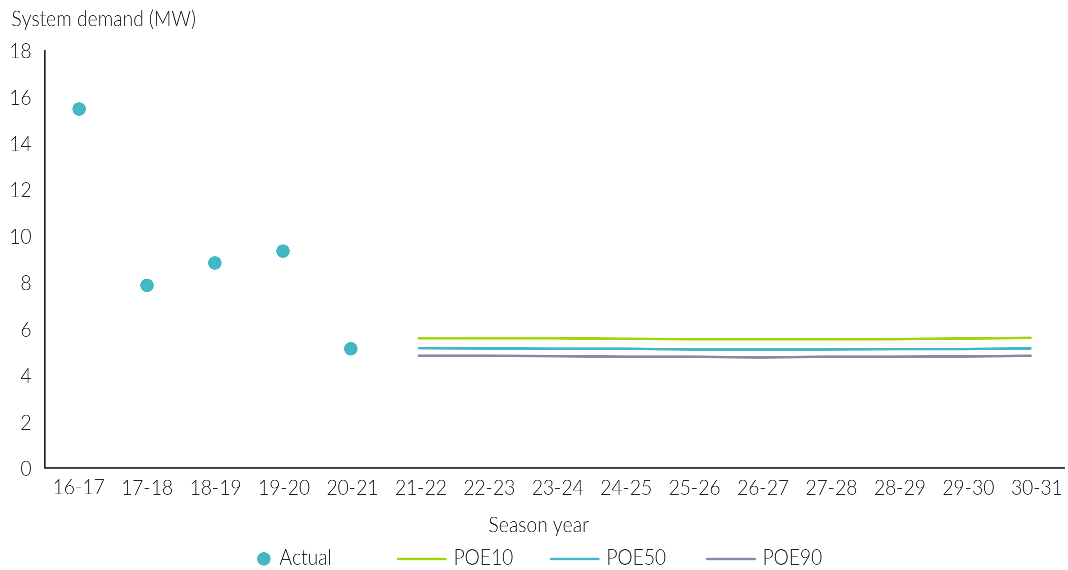
Figure 3: Historical and forecast maximum system demand for the Darwin node by season year (year ending 31 August), 2016-17 to 2030-31



Manton, Batchelor and Pine Creek forecast

Figure 4 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 2030-31.

Figure 4: Historical and forecast maximum system demand for the Manton, Batchelor and Pine Creek node by season year (year ending 31 August), 2016-17 to 2030-31



Consistent with annual electricity consumption, maximum system demand has historically been heavily influenced by industrial loads. The large drop in system demand over the historical period shown in Figure 4 is attributed to numerous mine closures. The 2020-21 maximum system demand of 5.2 MW occurred during the shoulder season at 17:30.

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 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 17:00 and 19:30 over the outlook period.

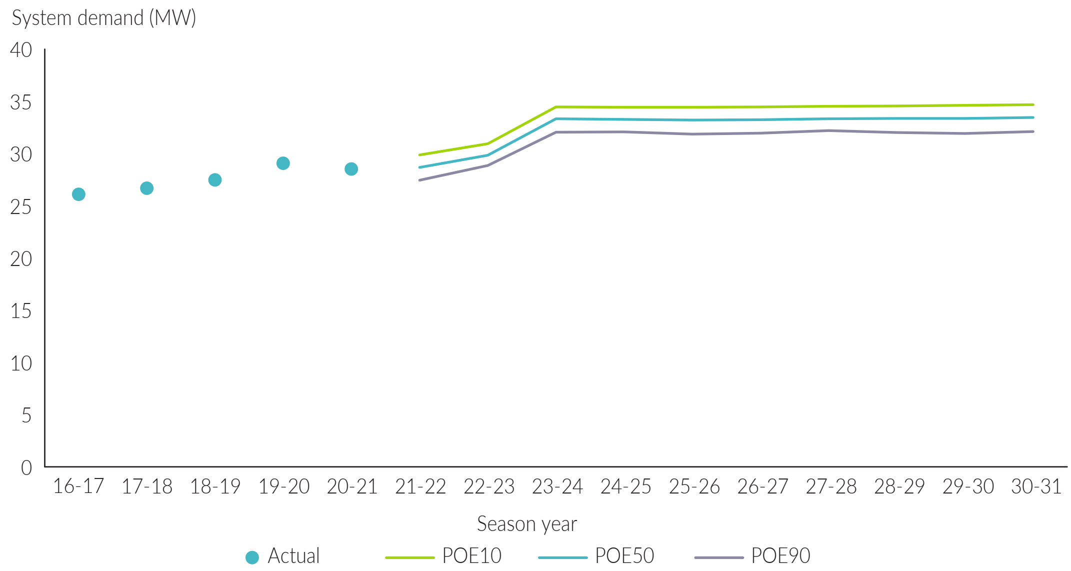
Katherine forecast

Figure 5 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 2030-31.

Maximum system demand has historically occurred in the mid-afternoon during the wet season and is driven by loads associated with cooling. The time of maximum demand is trending later in the day due to increasing uptake of distributed PV in the region. The 2020-21 maximum system demand of 28.5 MW occurred during the wet season at 16:00 and was 0.5 MW lower than the previous year.

Consistent with the annual electricity consumption forecast, maximum system demand is forecast to increase over the outlook period. The growth observed in the short term is attributed to forecast block load connections. From 2022 to 2026, the maximum is projected to occur between 16:00 and 18:30. From 2027 onwards, the maximum is projected to move later into the evening, to between 18:30 and 19:00. This gradual transition in the timing of maximum system demand to later in the day is due to forecast increases of distributed PV installed capacity.

Figure 5: Historical and forecast maximum system demand for the Katherine node by season year (year ending 31 August), 2016-17 to 2030-31



Minimum demand

Minimum demand forecasts for the Darwin-Katherine power system are reported per node.

Darwin forecast

Figure 6 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 2030-31.

Minimum system demand has historically occurred in the dry season in the early morning. The 2019-20 minimum system demand has been identified as unusually low. However, it was not excluded because it was not associated with a power system event or fault. The 2020-21 minimum system demand occurred at midday in the dry season at 74.0 MW, which was 14.4 MW higher than the previous year. The 2020-21 midday minimum suggests there is now sufficient distributed PV capacity installed in the node to shift the time of minimum system demand from early morning to midday.

Minimum system demand is forecast to decrease over the outlook period driven by increasing penetration of distributed PV. The minimum system demand is forecast to continue occurring in the dry season between 11:30 and 14:00, and is forecast below 20 MW at the end of the outlook period. As minimum demand continues to decline, management of the node will become increasingly challenging. This highlights the need for appropriate intervention to ensure the system stays secure and stable.

AEMO notes that actual outcomes may sit outside the POE ranges forecast, below the 90% POE minimum demand forecast for example, as seen in the Darwin node in 2019-20.

Figure 6: Historical and forecast minimum system demand for the Darwin node by season year (year ending 31 August), 2016-17 to 2030-31

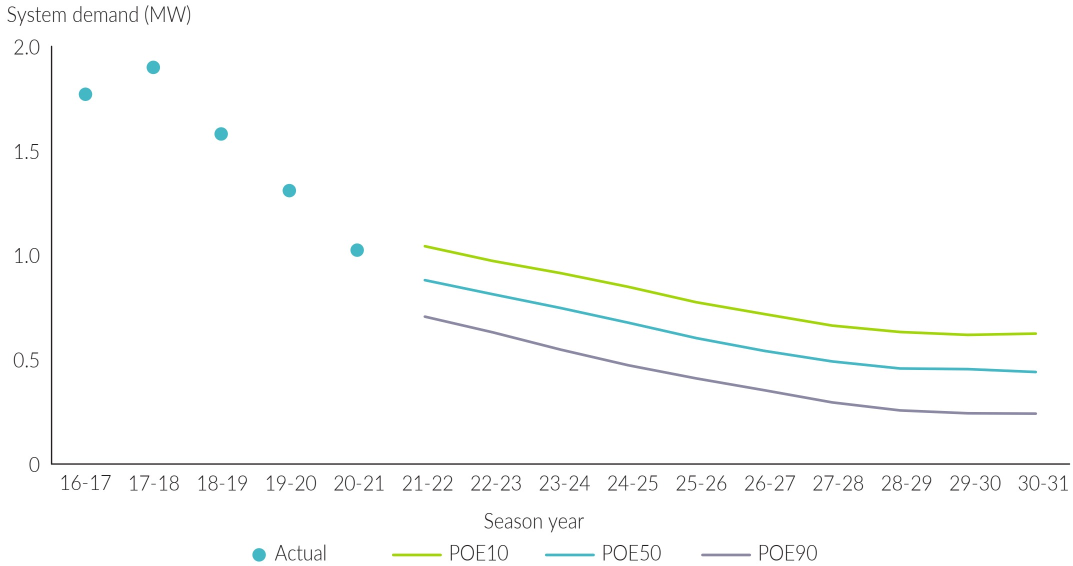
Manton, Batchelor and Pine Creek forecast

Figure 7 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 2030-31.

Minimum system demand has historically been heavily influenced by industrial loads, with minimum system demand coinciding with industrial outages at either Union Reef or Cosmo mine. The 2020-21 minimum system demand of 1.0 MW occurred during the shoulder season at 5:00 and was unaffected by any industrial load outages.

Minimum system demand is forecast to decrease over the outlook period. This decrease is due to a forecast increase in distributed PV in the short term before reaching full saturation. The minimum system demand is forecast to shift to between 10:00 and 13:30 over the outlook period.

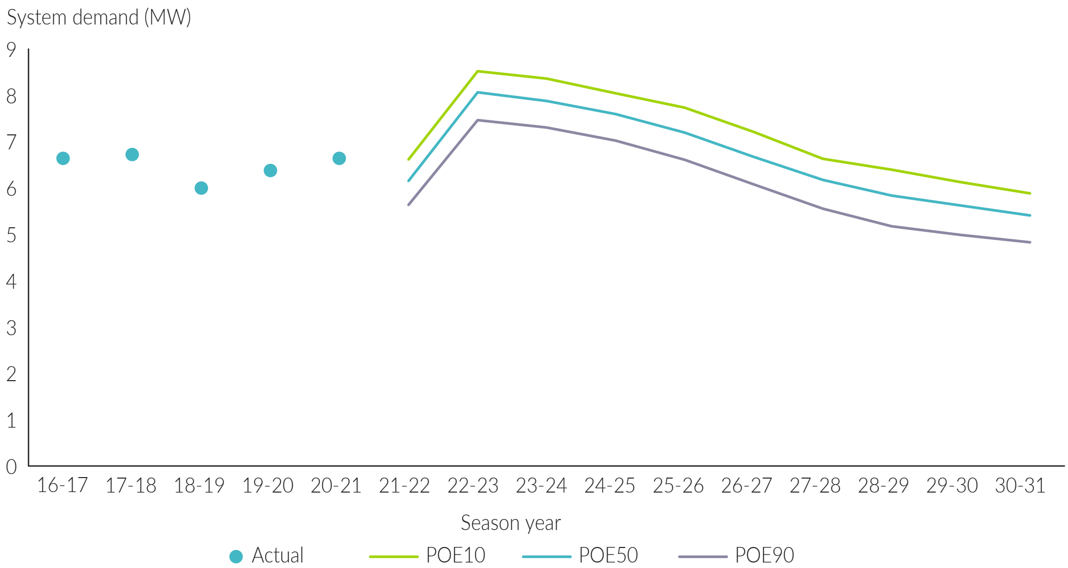
Figure 7: Historical and forecast minimum system demand for the Manton, Batchelor and Pine Creek node by season year (year ending 31 August), 2016-17 to 2030-31



Katherine forecast

Figure 8 shows annual historical and forecast minimum system demand by season year (year ending 31 August) at different POE levels in the Katherine node between 2016-17 and 2030-31.

Figure 8: Historical and forecast minimum system demand for the Katherine node by season year (year ending 31 August), 2016-17 to 2030-31



Minimum system demand has historically occurred in the early morning during the shoulder season. However, in 2017-18 the minimum occurred in the early morning of the dry season and in 2019-20 the minimum occurred at midday during the shoulder season. The 2020-21 minimum system demand of 6.6 MW occurred in the shoulder season at 5:00.

Minimum system demand is forecast to increase in the short term due to future block load connections, followed by a gradual decrease due to increasing distributed PV penetration. From 2023-24, the minimum system demand is forecast to occur during the dry season between 11:30 and 13:00. The decreasing trend and shift in time of day and season are driven by increasing penetration of distributed PV in the region.

System and underlying daily load profile

Figure 9, Figure 10 and Figure 11 show typical daily load profiles under maximum and minimum demand conditions in the Darwin; Manton, Batchelor and Pine Creek; and Katherine nodes for 2020-21, 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 2020-21, the annual maximum occurred in the wet season for the Darwin and Katherine nodes, and in the shoulder season for the Manton, Batchelor and Pine Creek node. 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 for the Darwin node, and in the shoulder season for the Manton, Batchelor and Pine Creek, and Katherine nodes. The light blue and green lines represent the maximum underlying and system demand respectively. The dark blue and purple lines represent the minimum underlying 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. For Darwin, the amount of distributed PV installed has shifted the minimum to a midday minimum. For Manton, Batchelor and Pine Creek, and Katherine, the minimum still occurred in the early morning for 2020-21. In all nodes, the impact from distributed PV during the day is similar for both seasons although it is slightly greater for the dry season for the Darwin node.

Figure 9: Daily load profiles for the Darwin node, wet and dry seasons, 2020-21

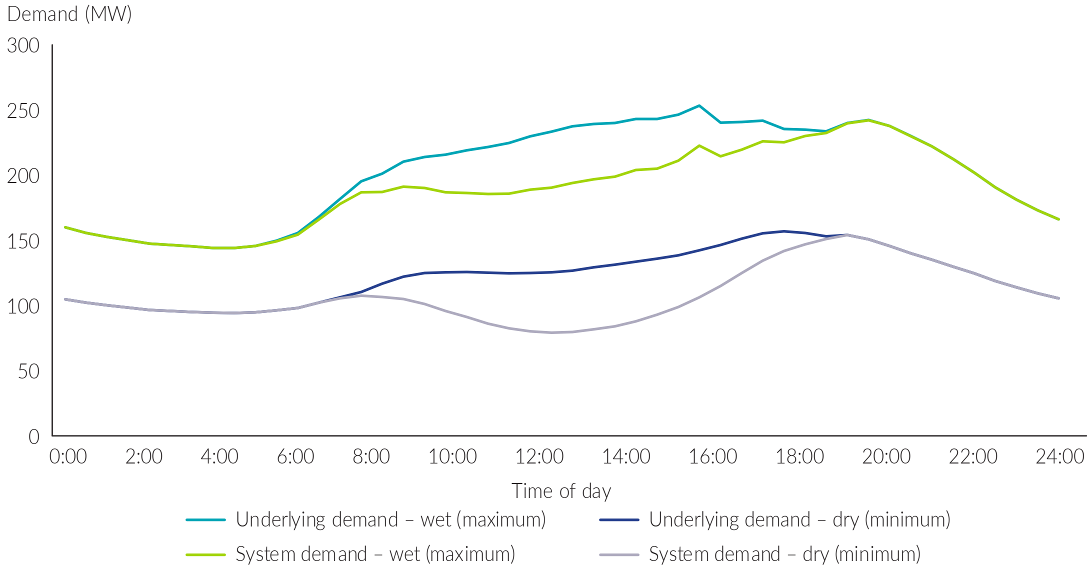


Figure 10: Daily load profiles for the Manton, Batchelor and Pine Creek node, shoulder season, 2020-21

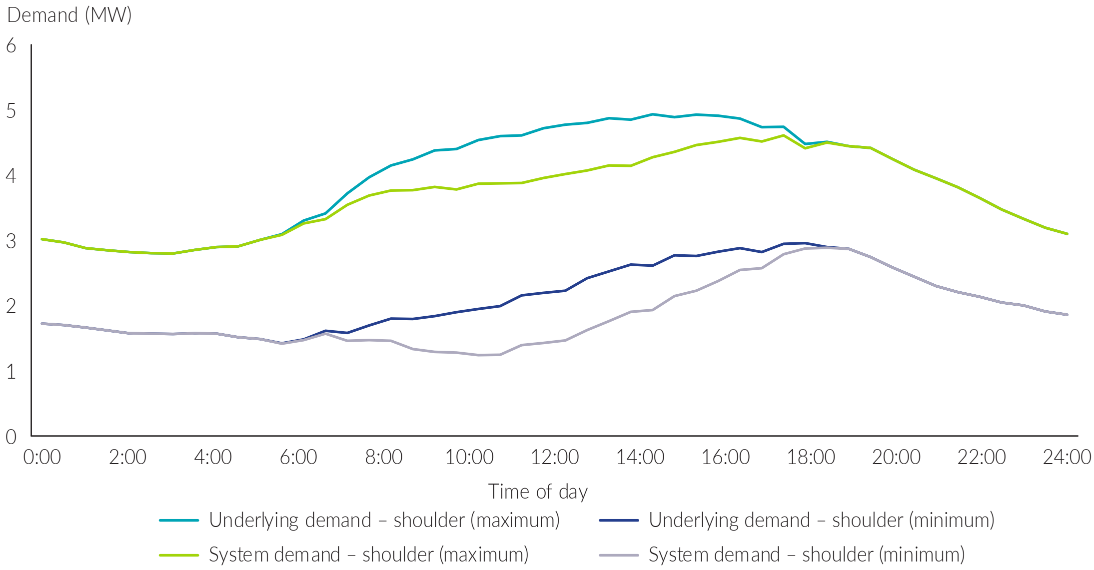
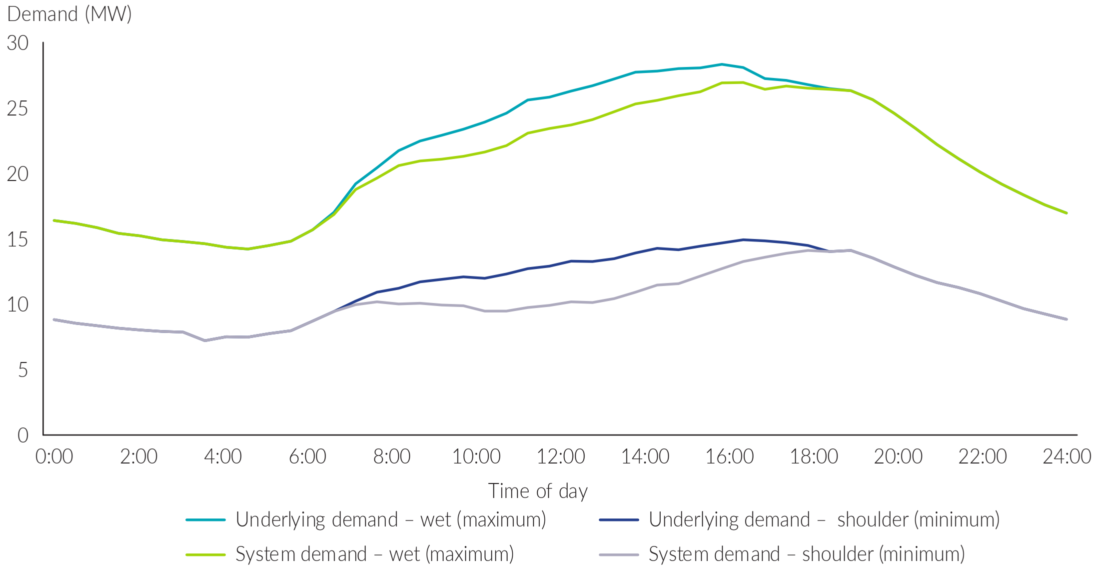


Figure 11: Daily load profiles for the Katherine node, wet and shoulder seasons, 2020-21



Supply adequacy outlook

Unserved energy outcomes

Given current levels of generation availability, expected USE in the Darwin-Katherine power system is forecast to be relatively low and stable in the initial years of the outlook period. The expected outcome improves further following the assumed commissioning of numerous large-scale solar power stations in 2022-23, and after CIPS 10 becomes available in 2024-25.[8] Forecast USE, however, increases substantially in the later years of the outlook following the retirement of a number of generating units at CIPS and KPS. For more details on retirement dates, see Appendix A1.8.2, Table 4.

Figure 12 shows the year-by-year results with the last four years of the outlook period shown separately on a new axis due to the magnitude of forecast USE. USE is forecast to exceed 0.6% of annual underlying electricity consumption in the final year of the outlook period. While still remaining high, this projection is substantially lower than forecasts made in previous years, predominantly due to the new CIPS 10 unit that is now expected to be operating from 31 December 2023. Despite the effect of this unit, the forecasts still indicate further additional generation, demand response and or storage solutions will be required to offset the impact of generation retirements to maintain the current level of reliability. Detailed USE forecasts are shown in Appendix A2.2.

8 The scheduled CIPS 10 start date is 31 December 2023. This is after the most critical period for USE of financial year 2023-24. Its effect on USE is only fully observed in the financial year 2024-25 and after.

Figure 12: Forecast reliability, Darwin-Katherine, 2021-22 to 2030-31

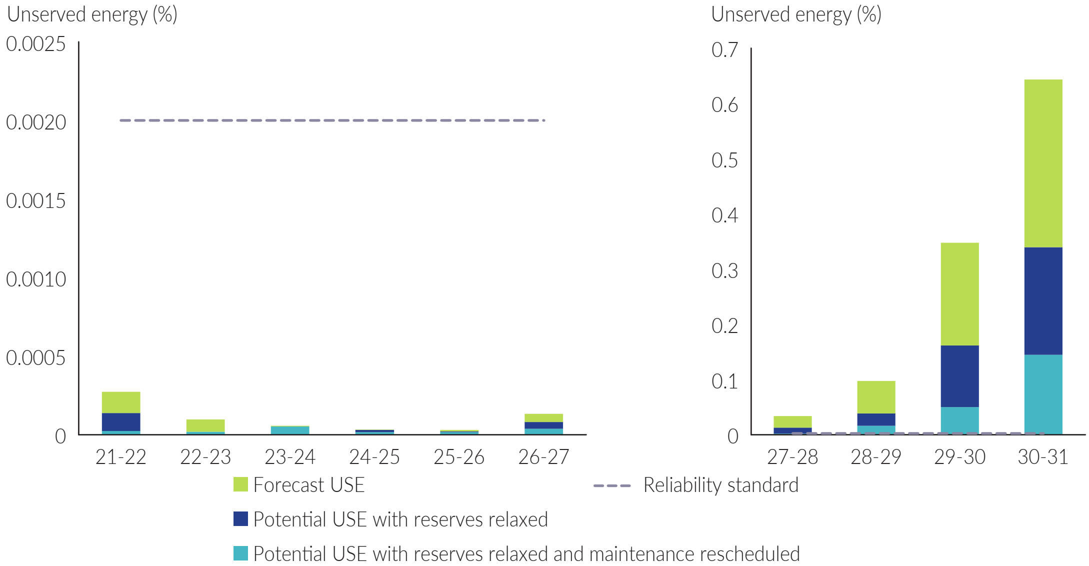


Figure 12 also shows forecasts using alternate modelled sensitivities, which project that consumer reliability outcomes could be improved where reserve requirements can be relaxed and or generator maintenance can be rescheduled. These sensitivities show the potential for improving short-term reliability for consumers, but result in additional risks, which could include a system black in extreme circumstances. Overall, the analysis suggests that there is sufficient capacity to ensure reliability remains within the adopted reliability standard until 2027-28.

However, some of the nodes within the Darwin-Katherine power system show different reliability risks due to the impact of transmission limitations. While the Darwin node shows results consistent with the overall system trend but in a smaller magnitude, Katherine shows slightly higher risks and the Manton, Batchelor and Pine Creek node shows significantly lower risks than the power system as a whole. These three nodes are connected by a 132 kilovolt (kV) transmission line that is subject to numerous thermal and system security limitations.

Figure 13 and Figure 14 show projected USE for the two nodes south of Darwin. The smaller node of Manton, Batchelor and Pine Creek shows low levels of USE until risks in the overall power system increase, although at a lower level. The Katherine node, which is subject to the most stringent transmission limitations, shows reduced performance compared with the overall power system in both the initial and later years. This suggests that further location-specific solutions may be required.

Figure 13: Forecast reliability, Manton, Batchelor and Pine Creek node, 2021-22 to 2030-31

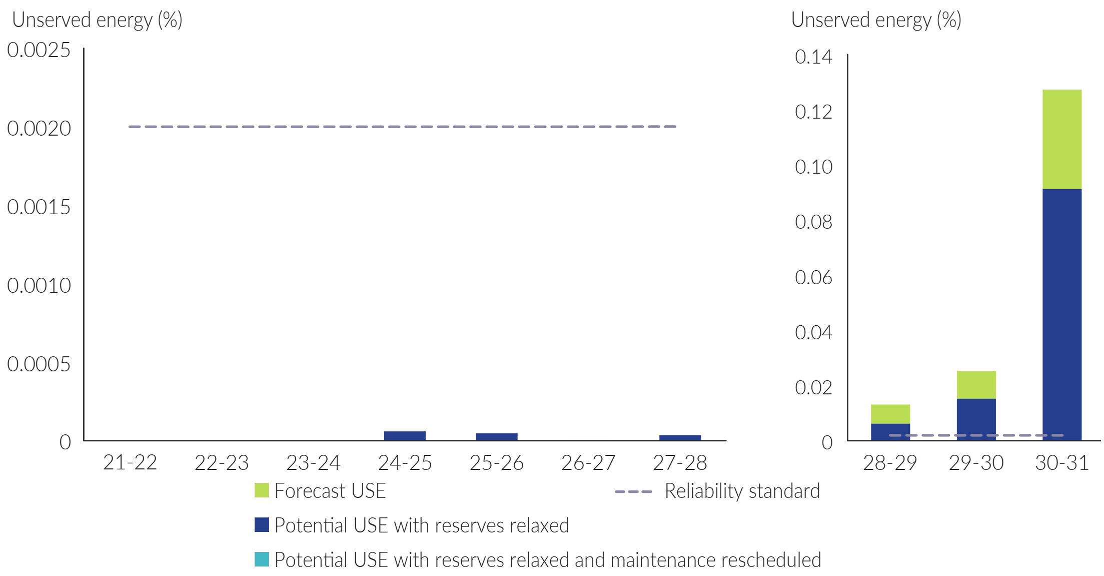
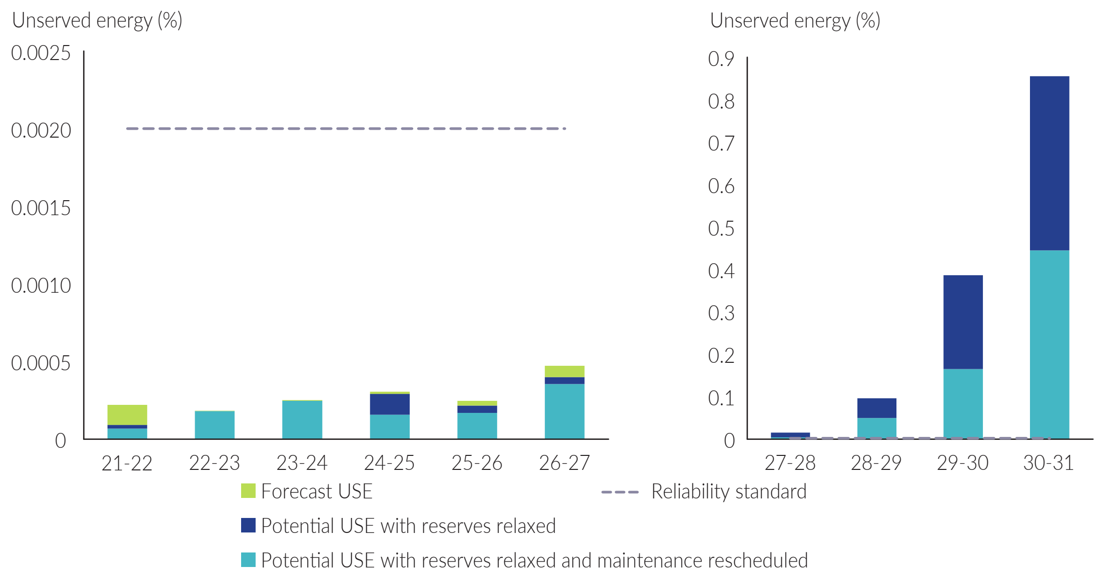


Figure 14: Forecast reliability, Katherine node, 2021-22 to 2030-31

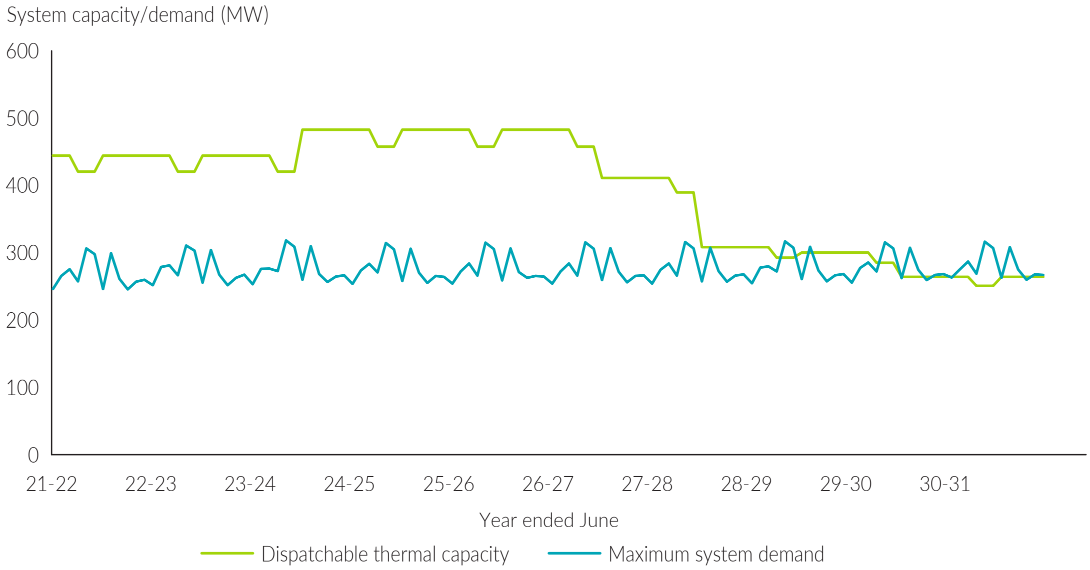


Reserve capacity

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

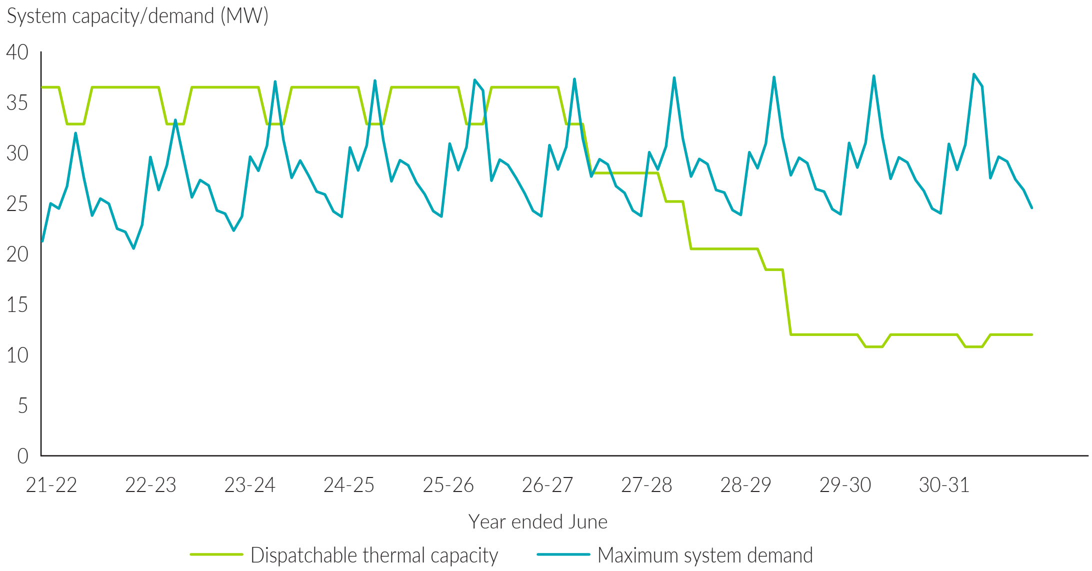
Figure 15 shows the seasonal dispatchable capacity against monthly maximum forecast demand for the Darwin-Katherine power system. This figure does not account for the contribution from sources that are not fully dispatchable, such as the large-scale solar power stations that are assumed to complete commissioning at the start of the outlook period. A more detailed description of the supply assumptions can be found in Appendix A1.8.

Figure 15: Forecast seasonal dispatchable capacity and monthly maximum system demand (POE10), Darwin-Katherine, 2021-22 to 2030-31



Katherine has the tightest reserve capacity of the three nodes, as shown in Figure 16. This is exacerbated by an increase in forecast maximum demand in 2022-23 and 2023-24, which is then sustained, and a reduction in available dispatchable supply from 2026-27 after the retirement of KPS units.

Figure 16: Forecast seasonal dispatchable thermal capacity and monthly maximum subregional demand (POE10), Katherine node, 2021-22 to 2030-31



System minimum implications

Minimum system demand is forecast to decline rapidly in the Darwin-Katherine power system, following the increasing penetration of distributed PV. By the end of the outlook period, system minimums are forecast to be less than 20 MW, which may 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 to assist in mitigating these risks, including:

- incentivising more demand during the middle of the day through effective market and regulatory arrangements
- innovative solutions such as providers and aggregators of distributed energy resources (DER) offering services including increased PV system controllability, load flexibility, storage, and load shifting
- ensuring all new distributed PV installations have suitable disturbance ride-through and emergency shedding capabilities which could 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 2020 and 2021 NEM *Electricity Statement of Opportunities* (ESOO)[9] and *2020 System Strength and Inertia Report*.[10]

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 generation, transmission, DER or demand-side participation.

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

- the Darwin-Katherine electricity system plan.[11] This plan involves the development of new Renewable Energy Hubs, as well as increased levels of small-scale solar and battery energy storage systems. Should the developments from this plan progress, the reliability outlook would improve considerably
- Territory Generation's draft fleet transition plan business case (not published but various drafts were provided to the Commission). This plan includes a proposal to replace retiring capacity with new gas-fired generators and BESS to replace capacity, energy and essential system services. Such a proposal has the potential to improve the outlook considerably

9 See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf and https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf.

10 See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-System-Strength-and-Inertia-Report.

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

- SunCable's solar generation and transmission project (Australia-Asia Power Link).[12] While this project is still under development and yet to reach financial close,[13] the generation and storage capacity proposed by this project has the potential to improve the generation capacity outlook considerably if connected to the Darwin-Katherine power system.

AEMO and the Commission have not sought to determine whether these plans are feasible or the best solutions to address the forecast reliability risks over the outlook period, including from technology, regulatory, energy security or cost perspectives as it is outside the scope of this report. Further, implementation of one or more of these plans could raise new system security issues that would need to be considered.

12 See https://suncable.energy/.

13 See https://suncable.energy/wp-content/uploads/FINAL-SC_220624_Media-Release_Sun-Cables-Australia-Asia-PowerLink-deemed-investment-ready-by-Infrastructure-Australia.pdf.

2 | Alice Springs outlook

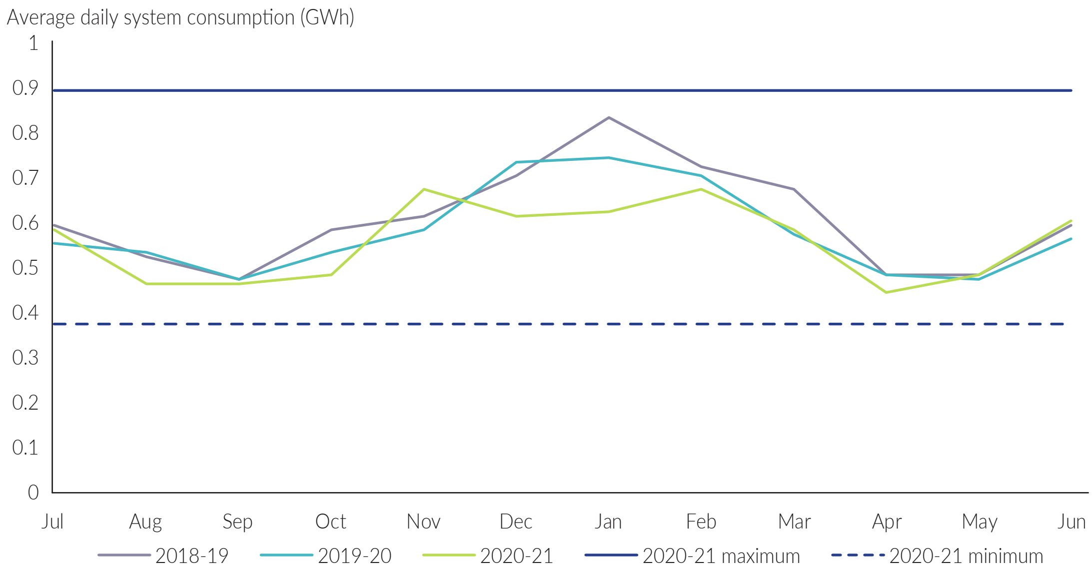
Annual electricity consumption

Electricity consumption observed in 2020-21

In 2020-21, the total annual system consumption in the Alice Springs power system was 202 GWh. This was 3.4% lower than system consumption in 2019-20.

Figure 17 shows average daily system consumption by month over the last three financial years. Average daily system consumption in 2020-21 was 0.58 GWh, and the daily maximum and daily minimum system consumption was 0.89 GWh and 0.37 GWh respectively. The month-to-month variability in system consumption indicates Alice Springs has relatively strong seasonable variability.

Figure 17: Daily average system consumption for Alice Springs by month, 2018-19 to 2020-21

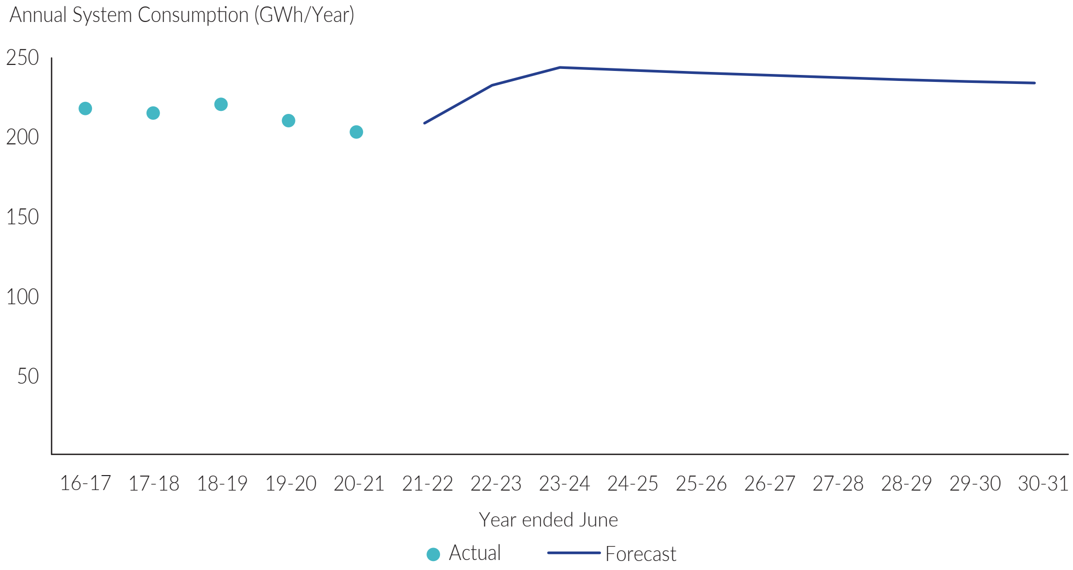


Recent history and forecast

Figure 18 shows historical and forecast annual system consumption in the Alice Springs power system from 2016-17 to 2030-31. The historical values of annual system consumption show a general decline since 2016-17. This trend is largely driven by increases in distributed PV.

Forecast annual system consumption is expected to increase in 2022-23 and 2023-24 due to the JDFPG connecting midway through 2022-23. Annual system consumption is forecast to decline after 2023-24 due to projected growth in distributed PV. Other long-term trend drivers, including population projections, are also expected to contribute to this forecast decline.

Figure 18: Historical and forecast annual system consumption for Alice Springs, 2016-17 to 2030-31



Maximum demand

Figure 19 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 2030-31.

Figure 19: Historical and forecast maximum system demand for Alice Springs by season year (year ending 31 August), 2016-17 to 2030-31

Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with cooling. However, the time at which maximum system demand occurs in the Alice Springs system is trending later in the day due to the increasing penetration of distributed PV. In 2020-21, maximum system demand of 52.8 MW occurred in the summer season at 17:30.

Maximum system demand is forecast to increase over the outlook period, with most of this growth attributed to a sizeable new block load connection. The forecast increases of distributed PV installed capacity push the time of maximum demand later in the day. Once this has pushed beyond sunset, it is expected there will be no further impact of distributed PV on maximum system demand. The maximum system demand is forecast to occur between 16:00 and 18:30 over the outlook period and to remain in the summer season.

Minimum demand

Figure 20 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 2030-31. From 2016-17 onwards, the minimum system demand has occurred in the shoulder season during the middle of the day, with the 2020-21 minimum system demand of 8.65 MW occurring at 11:00.

Minimum system demand is forecast to increase in 2022-23 and 2023-24, before trending downwards for the remainder of the outlook period. The initial increase in forecast minimum system demand is largely influenced by the expected connection of a sizeable new block load into the Alice Springs system. Following the full connection of this load, projected in 2023-24, minimum system demand is forecast to decline for the remainder of the outlook period as distributed PV continues to grow. The minimum system demand is forecast to continue occurring in the middle of the day; however, the month in which the minimum occurs is expected to be either April or September (the shoulder season).

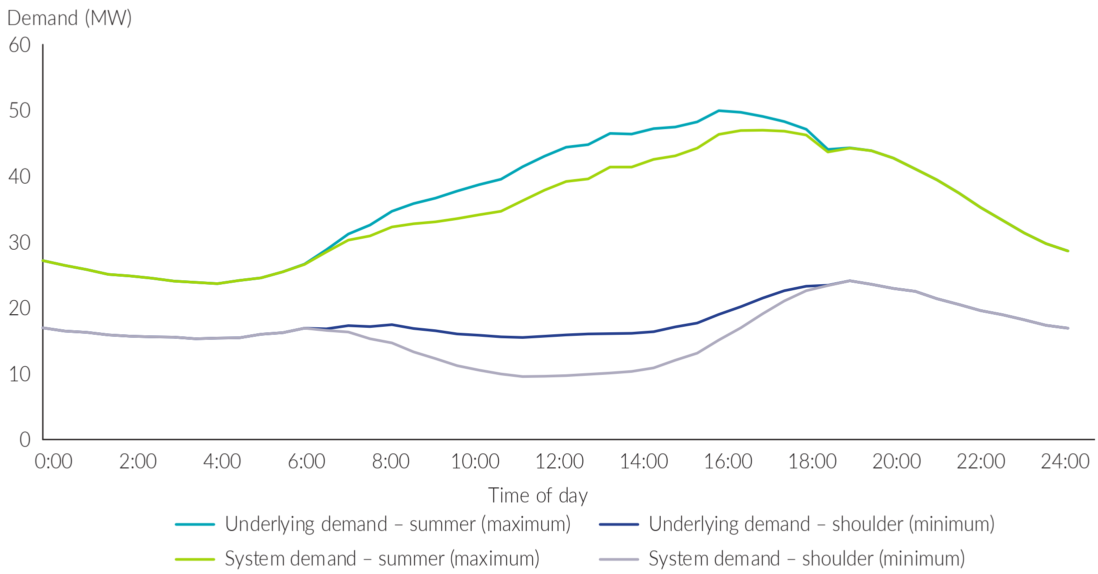
Figure 20: Annual historical and forecast minimum system demand for Alice Springs by season year (year ending 31 August), 2016-17 to 2030-31

System and underlying daily load profile

Figure 21 shows typical daily load profiles under maximum and minimum demand conditions in the Alice Springs power system for 2020-21. The maximum demand profile represents the average of the 10 highest demand values in the summer season. The minimum demand profile represents the average of the 10 lowest demand values in the shoulder season. The light blue and green lines represent the maximum underlying and system demand, respectively. The dark blue and purple lines represent the minimum underlying and system demand, respectively.

As expected, distributed PV generation during the day has lowered maximum system demand during summer. Distributed PV has lowered the daytime minimum in the shoulder season to such an extent that the minimum system demand consistently occurs during the daytime.

Figure 21: Daily load profile for Alice Springs, summer and shoulder seasons, 2020-21



Supply adequacy outlook

Unserved energy outcomes

Figure 22 shows expected USE in Alice Springs is forecast to be above the 0.002% adopted reliability standard in the first two years, when the new OSPS units (5 to 14) are forecast to have high forced outage rates, and again from 2026-27, when the RGPS is assumed to be fully retired. The detailed USE forecast is shown in Appendix A2.2.

The new OSPS units have shown high levels of forced outages in their short operating history, due to unforeseen technical issues. To reflect the risks arising from such outage rates, the outlook assumes these units will retain their actual outage rate since commissioning of 32.1% for the first forecast year, and will then gradually reduce to the 1.0% rate proposed by the licensee after three years (for more information, see Appendix A1.8.6, Table 7). These assumptions impact results for the first two years in particular, however by the third year the projected outage rate is sufficiently low for expected USE to be below the 0.002% standard.

Forecast USE in this outlook is generally lower than that in the 2020 NTEOR, predominantly due to the postponed retirement dates assumed for the RGPS (see Appendix A1.8 for more details). The model suggests the Ron Goodin units will still contribute as back-up generators and as reserve-providing units, despite being at the end of their life cycle with low reliability. However, this added power system reliability and security comes at an increased cost to Territory Generation, and thus consumers or taxpayers. When the RGPS is fully retired, USE is expected to increase from 0.001% in 2025-26 to 0.016% in 2026-27 and 0.020% in 2027-28, well above the 0.002% standard. This highlights an emerging reliability and operability challenge in the Alice Springs power system.

Although USE is forecast to decrease in 2028-29 and 2029-30, this is due to low levels of scheduled maintenance in these years. Expected USE rebounds in 2030-31 when scheduled maintenance returns to higher levels. The maintenance events considered in the model are informed by industry participants and represent the best projection of scheduled outages at the time of the simulation. These outages are likely to be rescheduled by the participant or PWC System Control closer to the time of event if they are deemed to have any potential negative impact on customers.

Figure 22: Forecast reliability, Alice Springs, 2021-22 to 2030-31

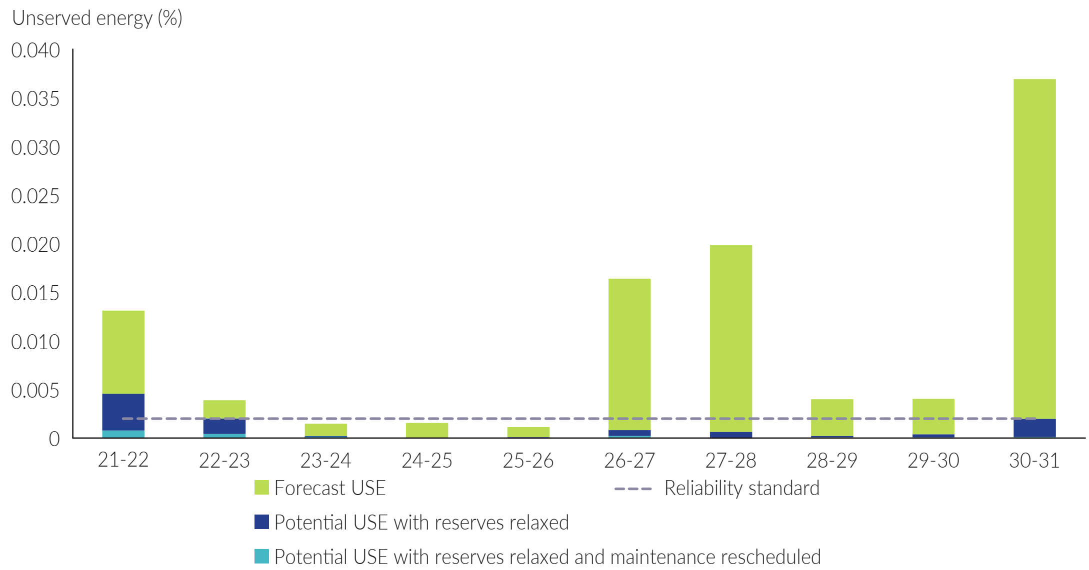
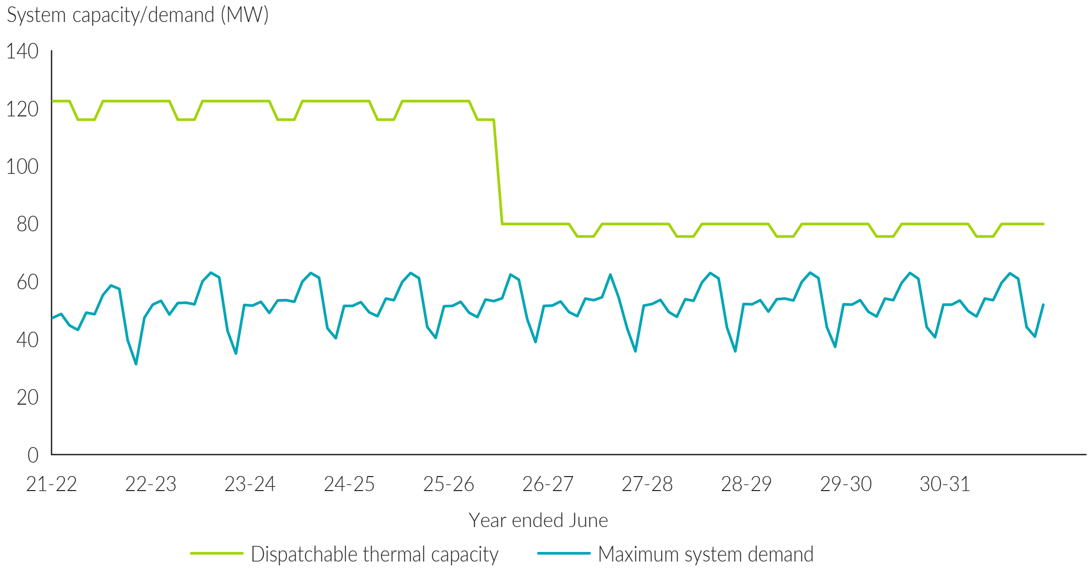


Figure 22 also shows forecasts using alternate modelled sensitivities, which indicate consumer reliability outcomes could be improved where reserve requirements are relaxed and or generator maintenance is rescheduled. These sensitivities show the potential for improving short-term reliability for consumers but result in additional risks, such as a system black in extreme circumstances. Overall, the analysis suggests reliability and operability challenges persist over the outlook period.

Reserve capacity

Figure 23 shows how surplus seasonal dispatchable capacity declines towards the middle of the outlook period against monthly maximum system demand, following the assumed retirement of the RGPS by the end of 2026. The figure also shows a slight increase in forecast maximum demand from 2022-23 after a sizeable block load connects to the power system. After that, maximum demand is expected to remain stable until the end of the outlook period.

Figure 23: Forecast seasonal dispatchable capacity and monthly maximum demand (POE10), Alice Springs, 2021-22 to 2030-31



Despite relatively low levels of forecast USE, the reduced amount of generation capacity reserves demonstrates the continued importance of coordinated outage planning at the OSPS and in the Alice Springs power system more generally. Suboptimal planning of scheduled outages will make the power system more vulnerable to USE events in the case of unplanned outages.

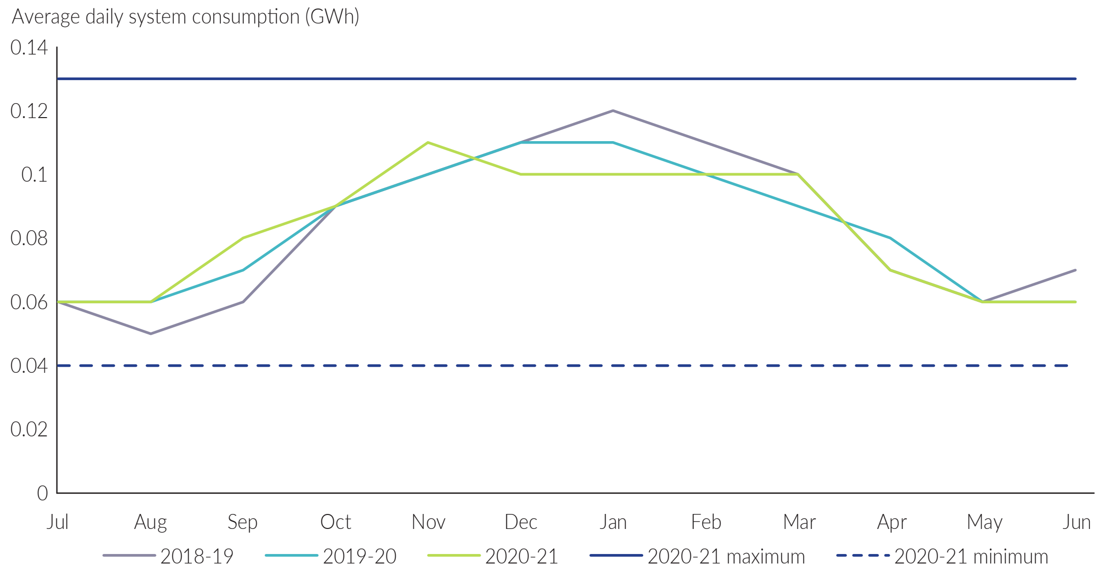
3 | Tennant Creek outlook

Annual electricity consumption

Electricity consumption observed in 2020-21

In 2020-21, total system consumption in the Tennant Creek power system was 29.9 GWh,[14] which is a 5.6% reduction from 2019-20. Figure 24 shows the average daily system consumption by month over the past three financial years in the Tennant Creek power system. Average daily system consumption in 2020-21 was 0.08 GWh, and maximum and minimum daily consumption were 0.13 GWh and 0.04 GWh respectively. The variability of consumption reflects the wide temperature changes between seasons experienced in the region.

Figure 24: Average daily system consumption for Tennant Creek by month, 2018-19 to 2020-21



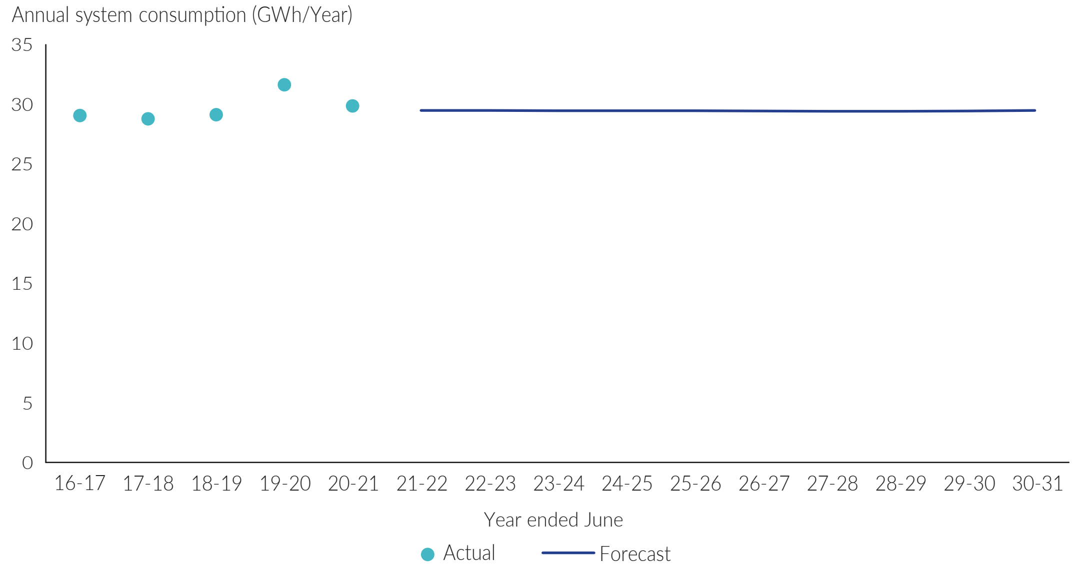
Recent history and forecast

Figure 25 shows historical and forecast annual system consumption in the Tennant Creek power system from 2016-17 to 2030-31. Historic system consumption observations have been relatively steady since 2016-17. The effect of distributed PV on annual system consumption has been relatively minor given the low uptake of households with 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.

14 Total annual daily system consumption may vary from the 2020-21 Northern Territory Power System Performance Review due to differences in the calculation methodology and or rounding.

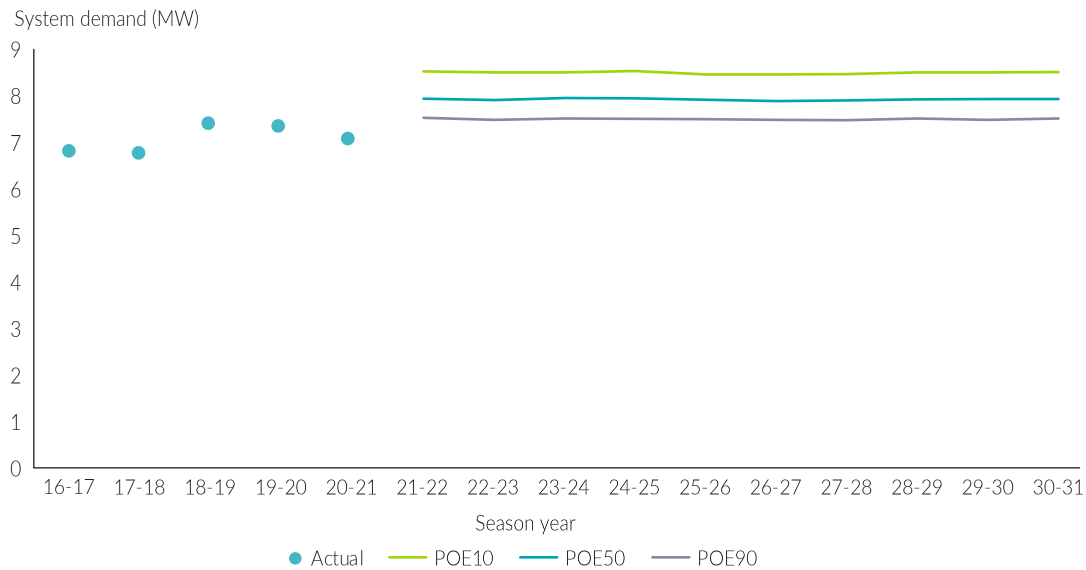
Figure 25: Historical and forecast annual system consumption for Tennant Creek, 2016-17 to 2030-31



Maximum demand

Figure 26 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 2030-31.

Figure 26: Historical and forecast maximum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2030-31



Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with cooling. The 2020-21 maximum system demand of 7.08 MW occurred in the summer season at 16:00. Maximum system demand is forecast to occur in the summer season between 14:00 and 17:00, due to the minimal effect of population drivers and small absolute growth in distributed PV.

Maximum system demand is forecast to be relatively flat across the outlook period. It is forecast to start slightly higher than the 2020-21 observed maximum. This is driven by the assumption of additional contributions from the Northern Gas Pipeline at the time of peak demand.

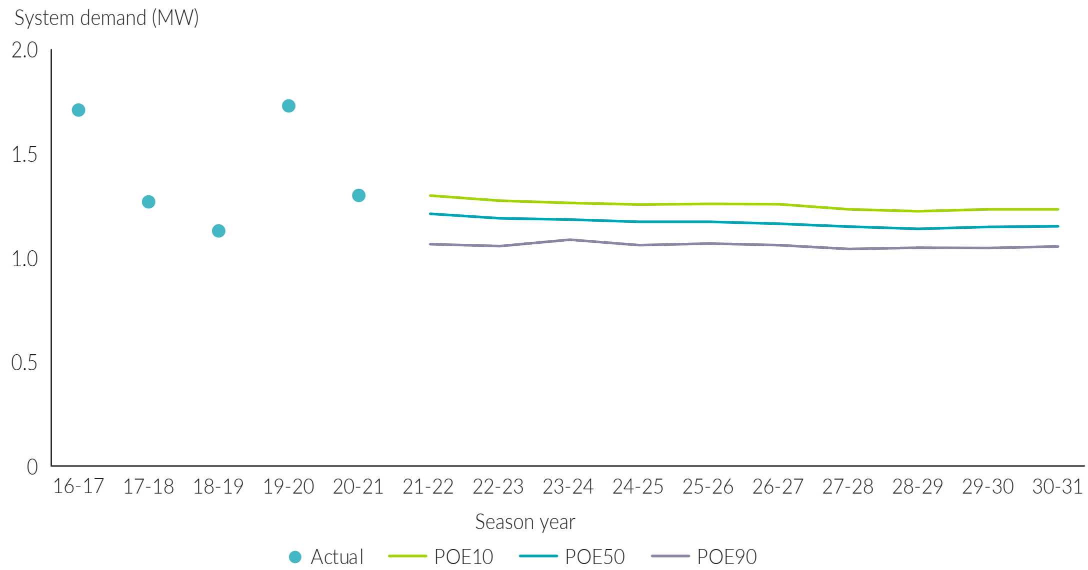
Minimum demand

Figure 27 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 2030-31.

Minimum system demand has historically occurred overnight in the shoulder season, however, in 2018-19 and 2019-20 the minimums occurred during the middle of the day at 14:30 and 11:00, respectively. The 2020-21 minimum system demand of 1.3 MW occurred in the shoulder season at 03:30. With small amounts of additional distributed PV installed capacity forecast in the coming years, minimum system demand is forecast to occur in the winter season during the middle of the day, between 12:00 and 14:30.

Minimum system demand is forecast to be relatively flat across the outlook period due to minimal forecast changes in population and small absolute growth in distributed PV installed capacity.

Figure 27: Historical and forecast minimum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2030-31

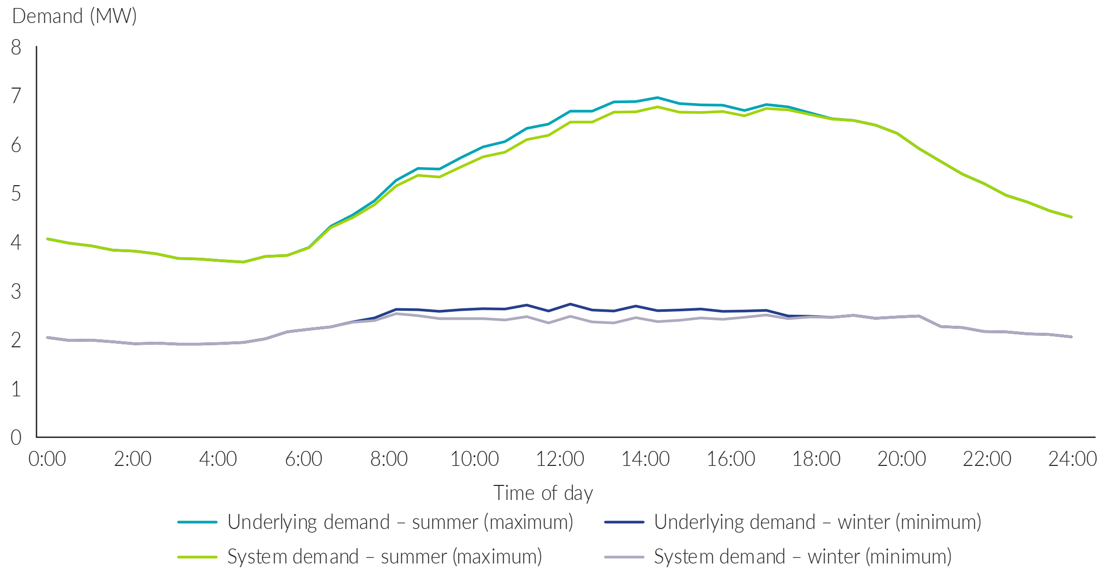


System and underlying daily load profile

Figure 28 shows typical daily load profiles under maximum and minimum system demand conditions in the Tennant Creek power system for 2020-21. 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 winter season.

The light blue and green lines represent the summer maximum underlying and system demand, respectively. The dark blue and purple lines represent the winter minimum underlying and system demand, respectively. Distributed PV generation during the day has lowered maximum system demand in summer and minimum system demand in winter. The minimum system demand still occurred overnight for 2020-21, however, it is forecast to shift to the middle of the day in the outlook period.

Figure 28: Daily load profile for Tennant Creek, summer and winter, 2020-21

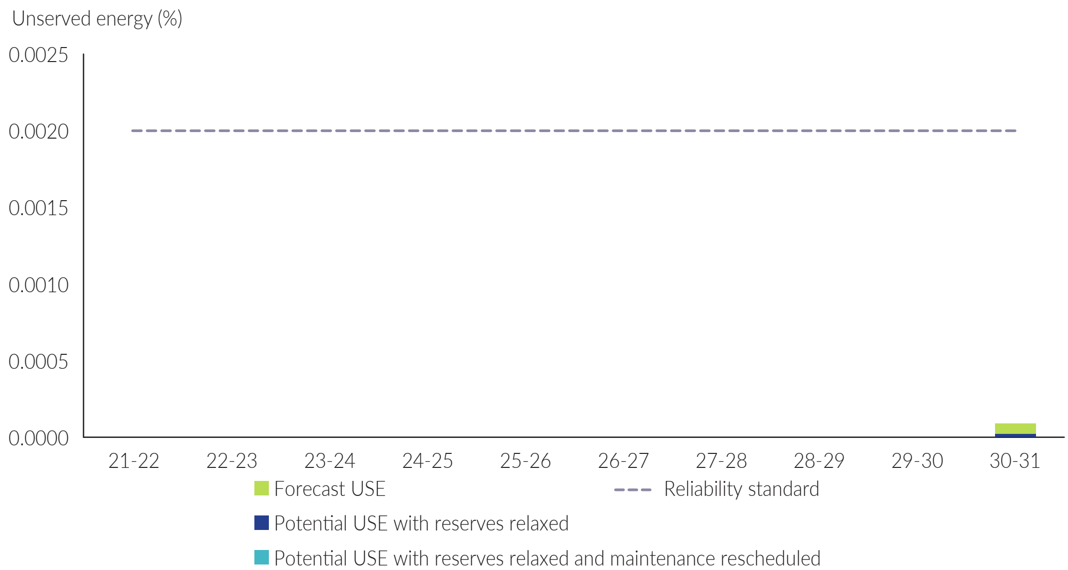


Supply adequacy outlook

Unserved energy outcomes

There is virtually no USE forecast in Tennant Creek across the outlook period. USE is forecast only in the last year, although it still remains below the adopted reliability standard of 0.002% USE. Figure 29 shows this value compared with the adopted reliability standard.

Figure 29: Forecast reliability, Tennant Creek, 2021-22 to 2030-31

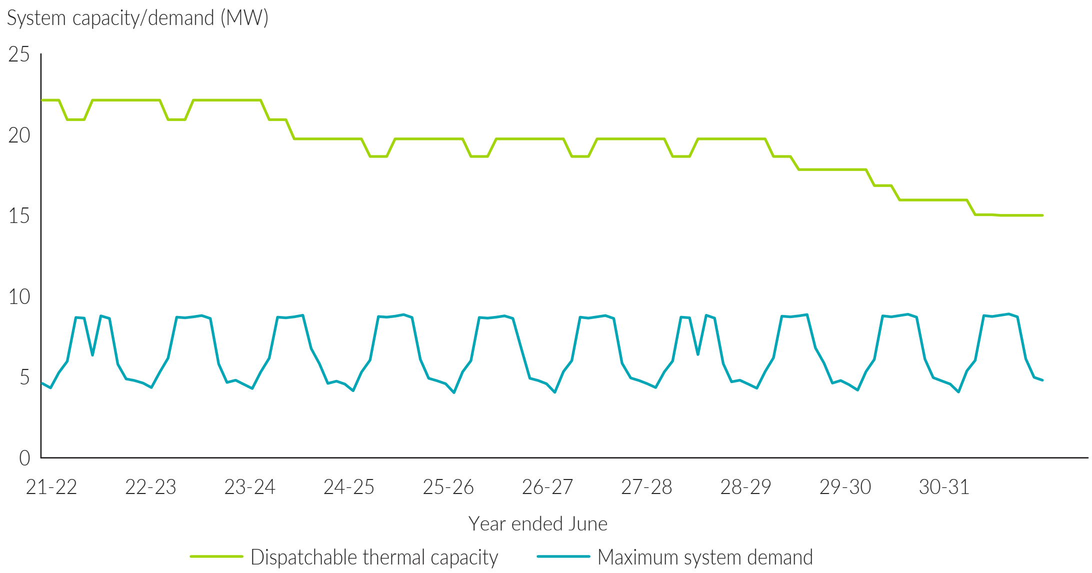


The low levels of USE forecast are mostly due to a surplus of generation capacity in the power system. Though beyond the scope of this report, there remains a possibility that USE could occur due to non-credible coincident outages across many generating units, noting multiple contingency events have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

Reserve capacity

As shown in Figure 30, the Tennant Creek power system has a substantial level of seasonal reserve capacity when compared to the forecast monthly maximum system demand. This results in almost no USE forecast in the first years and minimal impacts in the final years of the outlook period if reserve requirements are maintained at all times.

Figure 30: Forecast seasonal dispatchable thermal capacity and monthly maximum demand (POE10), Tennant Creek, 2021-22 to 2030-31



Appendix A1: Methodology and assumptions

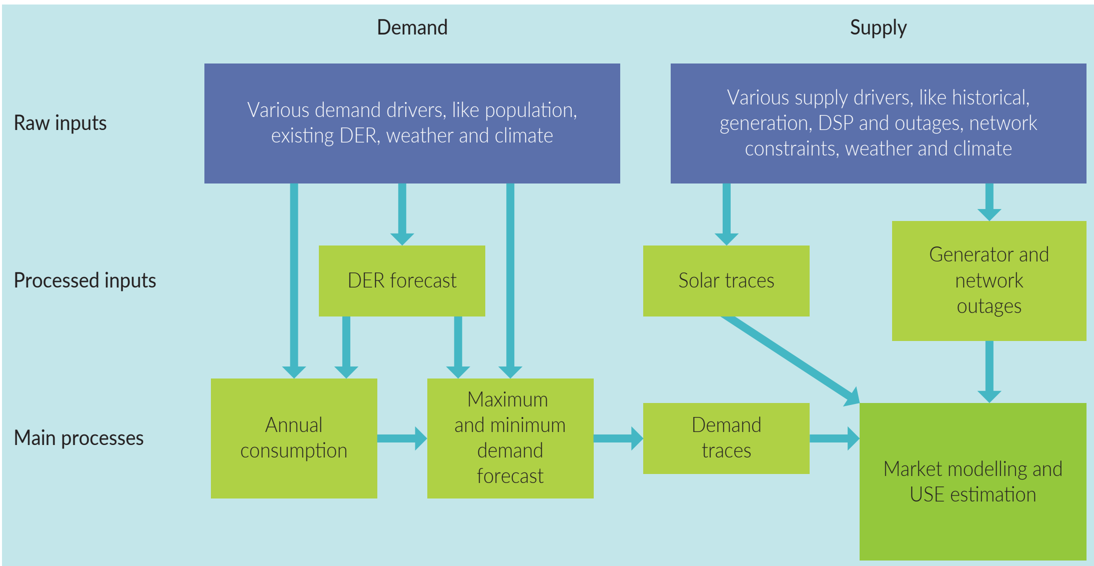
AEMO and the Commission undertook consultation on the methodology and assumptions proposed for use in the 2021 NTEOR. This consultation occurred in December 2021 and provided an opportunity for both written and verbal feedback on the proposed assumptions. Feedback was received from six stakeholders and the Commission. The methodology and assumptions used in the NTEOR have been refined based on this consultation. Final assumptions are documented in this section 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 31, 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. Simplifications and deviations from the NEM process are described in this section.

Figure 31: Forecasting components



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

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, batteries and EVs
- random drivers, which are modelled as a probability distribution and include weather drivers and generator outages

AEMO's forecasts for this year's 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 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 Territory Government's policy of 50% renewables by 2030.

A1.2.1 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 and the Commission use a generation adequacy assessment to determine whether available generation capacity, including an allocation for potential generation outages, is sufficient to meet consumer demand consistent with the Commission's adopted reliability standard of USE not exceeding 0.002% of total electricity consumption. This assessment is probabilistic and considers the requirement for essential system services.

While essential system services and generator maintenance are required under the majority of circumstances, AEMO models 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 this report
- 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 this report.

A1.3 Northern Territory power systems

This report includes analysis on the Territory's three largest power systems.

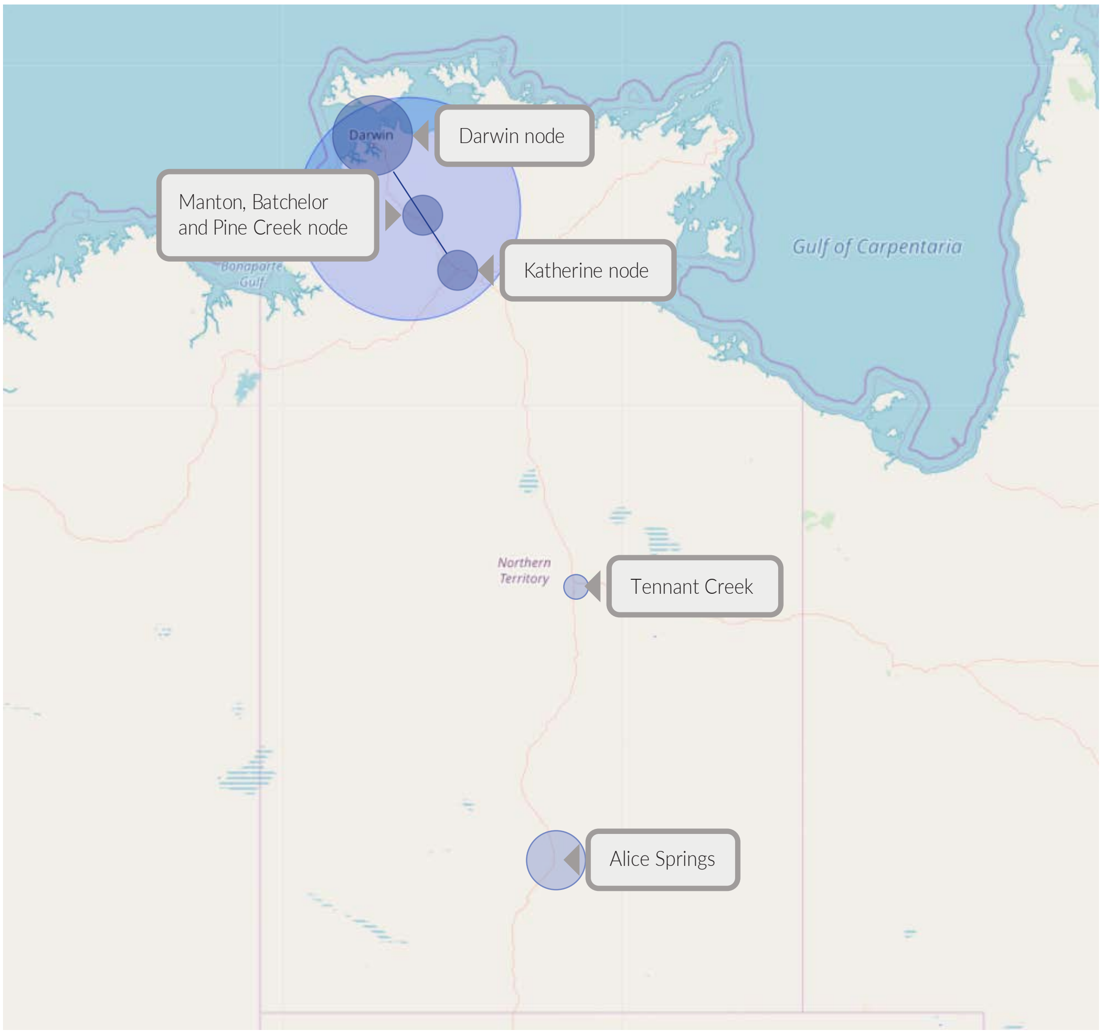
This year the Darwin-Katherine power system was split into three nodes for modelling purposes. These three nodes are connected by a 132 kV transmission line that may support the neighbouring node within the line's limitations. By modelling each node separately, the outlook can better identify challenges and opportunities in each subregion in addition to the broader regional analysis.

The three power systems and relevant Darwin-Katherine power system subregional nodes in the Territory are:

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

These three power systems are not connected to each other. The general location of each system within the Territory is shown in Figure 32. This outlook does not consider isolated systems in remote communities that are not connected to one of the Territory's three largest power systems.

Figure 32: Spatial representation of the Territory's three largest power systems and Darwin-Katherine subregional nodes



A1.4 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 electricity consumption forecast is a weather-based regression model, used to create a 'base year' forecast that represents consumption in a year with typical weather conditions. The model was built using daily system consumption data and 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 projected growth in population and uptake of distributed PV generation.

As with previous outlooks, gross state product (GSP) was not used as a growth driver in the forecasts. Statistical analysis suggests its correlation with electricity 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 Appendix A1.6.5.

A1.5 Maximum and minimum demand methodology

AEMO applied a regional demand forecasting methodology to forecast maximum and minimum demand, in line with the high temporal resolution demand models AEMO uses in forecasting maximum and minimum demand in the NEM.[15]

The methodology used for the Territory forecasts provides probabilistic demand forecasts by season because demand is dependent on weather conditions (primarily temperature). It 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).

A1.6 Demand assumptions

A1.6.1 Demand definitions

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

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

System demand, as provided by PWC System Control in 2021, includes generator auxiliary load (electricity used on-site by the generator) for existing Territory Generation-owned generators, while other generator connections were metered net of auxiliary loads.

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 produced 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.

15 See Electricity Demand Forecasting Methodology Information Paper, August 2020 at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

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 the effect of transmission and distribution losses will remain consistent with history throughout the forecast outlook period. For Darwin-Katherine, PWC Power Services estimated a transmission loss rate of 2.3% and a distribution loss rate of 2.7% when considering total system consumption in the 2020-21 financial year. The transmission and distribution losses for Alice Springs were estimated to be 5% and 2.6%, respectively. The distribution losses in Tennant Creek were estimated to be 1.5% in the 2020-21 financial year.

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

A1.6.2 Season definitions

The maximum and minimum 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 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. The supply adequacy assessments and input demand traces were, however, developed on a financial year basis.

A1.6.3 Demand data and network information

PWC Power Services and System Control provided:

- demand data, which is used to conduct historical analysis and construct forecasting models. Half-hourly data for each of the power systems or nodes 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.

A1.6.4 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 projections from the Northern Territory Government's Department of Treasury and Finance.[16]

16 Relevant projections can be found at https://treasury.nt.gov.au/dtf/economic-group/population-projections.

Table 1: Population growth rates adopted for demand forecast

Power system/node	Population growth rate (per annum) (%) 2021-22 to 2025-26	2026-27 to 2030-31	ABS statistical areas
Darwin	1.40	1.80	Greater Darwin (SA4)
Katherine	0.66	0.83	Katherine (SA3)
Manton, Batchelor and Pine Creek	0.58	0.70	Daly-Tiwi-West Arnhem (SA3)
Alice Springs	0.56	0.58	Alice Springs (SA3)
Tennant Creek	- 0.39	0.11	Barkly (SA3)

Forecast GSP, as noted in Appendix A1.4, 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 power system due to LNG projects that contribute significantly to GSP but consume relatively little or no electricity from the network. Limitations on data availability also prevent GSP projections from being adequately assigned to all the power systems or nodes.

A1.6.5 Block load changes

Significant load changes explicitly modelled in the annual consumption and maximum and minimum demand forecasts are described in Table 2. AEMO collected block load 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, where a new mine development is expected to commence in middle of the 2022-23 financial year. This load is expected to further increase in the middle of the 2024-25 financial year
- Darwin, where an LNG-associated load is expected to be connected early in the 2022-23 financial year. This load is anticipated to be in operation for two years
- Katherine, where upgrades to the existing Royal Australian Air Force (RAAF) Base Tindal are projected to increase electricity consumption from the middle of the 2022-23 financial year
- Alice Springs, where the existing JDFPG site is expected to become network-connected in middle of the 2022-23 financial year.

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

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

Power system/node	Site	Effective date	Status
Darwin	Mine development stage 1	1/01/2023	Connect
Darwin	Mine development stage 2	1/01/2025	Connect
Darwin	Temporary LNG project	1/07/2022 to 30/06/2024	Connect
Katherine	RAAF Base Tindal upgrade	1/01/2023	Connect
Alice Springs	JDFPG	1/11/2022	Connect
Tennant Creek	Mine development	1/07/2020	No longer considered in forecast

A1.6.6 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 the demand met by system demand
- large-scale PV systems operate as system generators and therefore contribute to network-supplied electricity. This is discussed in Appendix 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 projections. Future changes to PWC's Embedded Generation policy[17] were not included in the 2021 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 2021 NTEOR. AEMO considers the modelling of zero-export systems 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 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 with 8.3c/kilowatt hour (kWh) for new installations, new customers with existing installations and existing customers who make changes to their existing installation. Whilst the winding back of these programs initially slowed the rate of distributed PV installations, actual installed capacity in the 2020-21 financial year exceeded last year's forecasts for the same period. New installations are forecast to rebound in the first forecast year and onwards. 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. Further, the rate of distributed PV installations has been increasing across Australia, regardless of feed-in-tariff

17 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.

- modelling assumed 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 because commercial and existing residential dwellings dominate the PV installed capacity forecasts
- the base estimate of total residential installation rate for Darwin is 1,973 per year (over the past five years, these values have ranged from 1,244 to 2,735). The adopted rate for the Manton, Batchelor and Pine Creek node is 32 residential systems per year (the number of installations in the past five years has ranged from 18 to 35) and the rate for the Katherine node is 81 residential systems per year (the number of installations in the past five years has ranged from 45 to 125). The adopted rate for Alice Springs is 235 per year (the number of installations in the past five years has ranged from 163 to 322), and for Tennant Creek it is two per year (the past five years has mostly seen installation counts in the range of zero to seven)
- the installation rate was tapered for Darwin and Manton, Batchelor and Pine Creek 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 power systems or nodes were not tapered over the outlook period given their current lower installation levels
- in Darwin and Alice Springs, the new residential system size is forecast to grow marginally over the forecast outlook period based on a linear trend of the most recent four years of installation data. Due to volatility in historical system sizes, Manton, Batchelor and Pine Creek and Katherine 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 2021-22 (75 installations per year for Darwin, four per year for Manton, Batchelor and Pine Creek, 13 per year for Katherine, 15 per year for Alice Springs, and one per 36 months in Tennant Creek). This is supported by relatively stable installation counts seen in the past five years
  - for Darwin, Manton, Batchelor and Pine Creek and Katherine, modelling adopted the 2020-21 average installed capacity for new forecast commercial systems. For Alice Springs and Tennant Creek, where greater variability in historical data is observed relative to the Darwin-Katherine system, modelling incorporated data from earlier years. The average value drew upon data from 2017-18 to 2020-21 for Alice Springs and 2015-16 to 2020-21 for Tennant Creek
  - in Tennant Creek, an increase in forecast installed capacity is expected to occur in 2022-23. This increase in capacity aligns with information received from industry participants regarding upcoming solar projects

- 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 Appendix A1.8.

Residential and commercial PV generation was derived using half-hourly estimates of generation for each 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 could 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 33 shows forecasts for the whole of the Darwin-Katherine power system compared to forecasts used in the previous NTEOR. Figure 34, Figure 35 and Figure 36 show the forecasts used in the three Darwin-Katherine nodes. Figure 37 and Figure 38 show forecasts for the Alice Springs and Tennant Creek power systems, respectively, compared to forecasts provided for the 2020 NTEOR.

Figure 33: Aggregated historical and forecast distributed PV capacity, Darwin-Katherine, 2016-17 to 2030-31

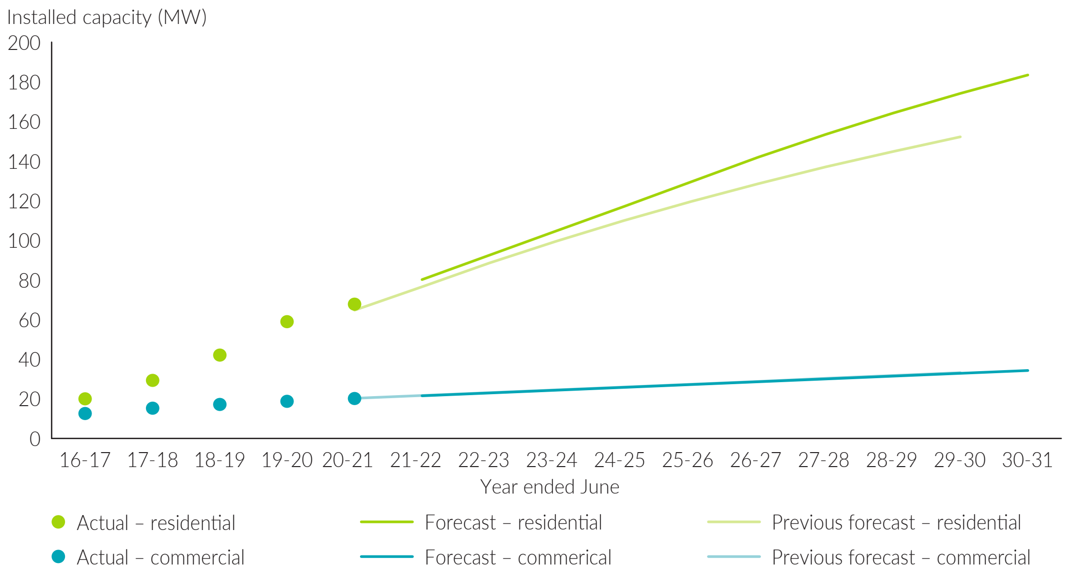


Figure 34: Historical and forecast distributed PV capacity, Darwin node, 2016-17 to 2030-31

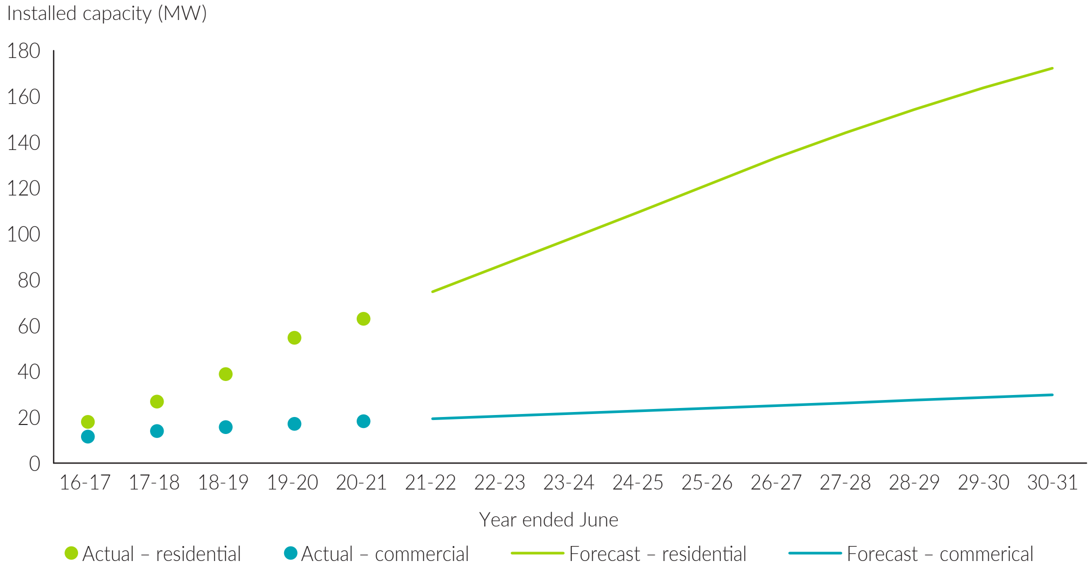


Figure 35: Historical and forecast distributed PV capacity, Manton, Batchelor and Pine Creek node, 2016-17 to 2030-31

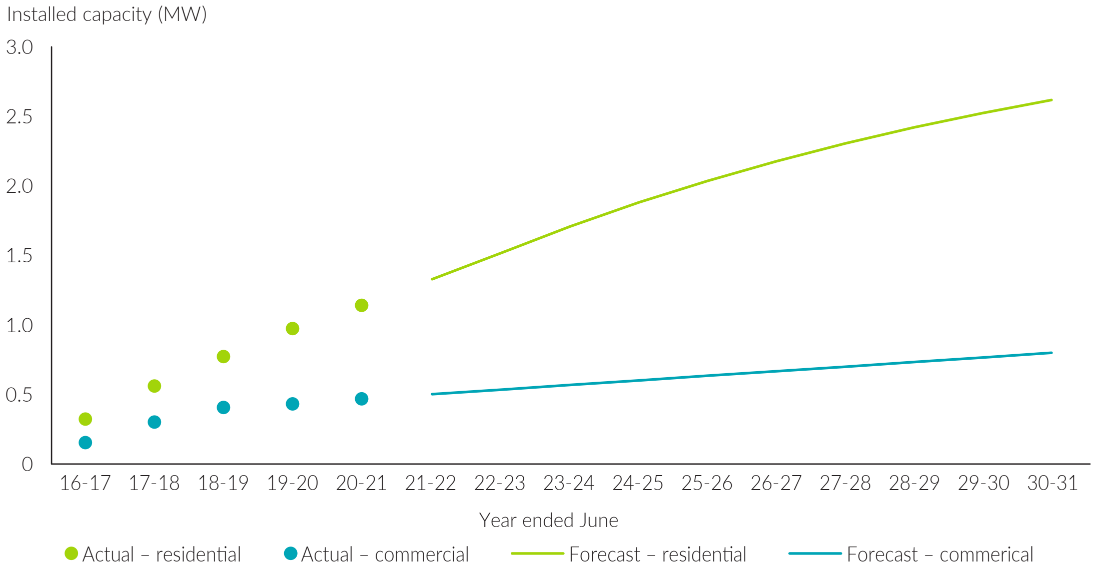


Figure 36: Historical and forecast distributed PV capacity, Katherine node, 2016-17 to 2030-31

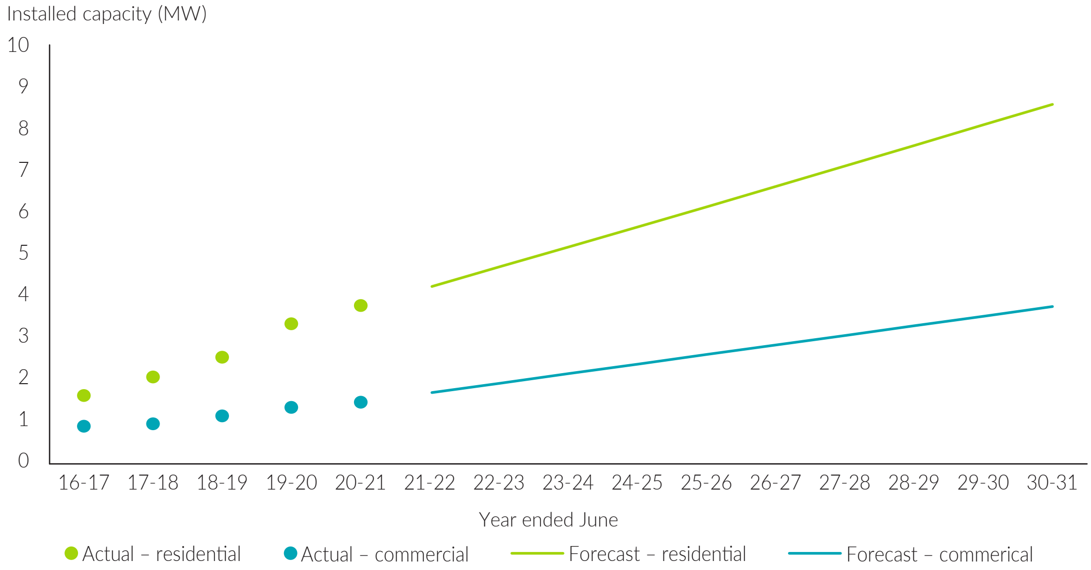


Figure 37: Historical and forecast distributed PV capacity, Alice Springs, 2016-17 to 2030-31

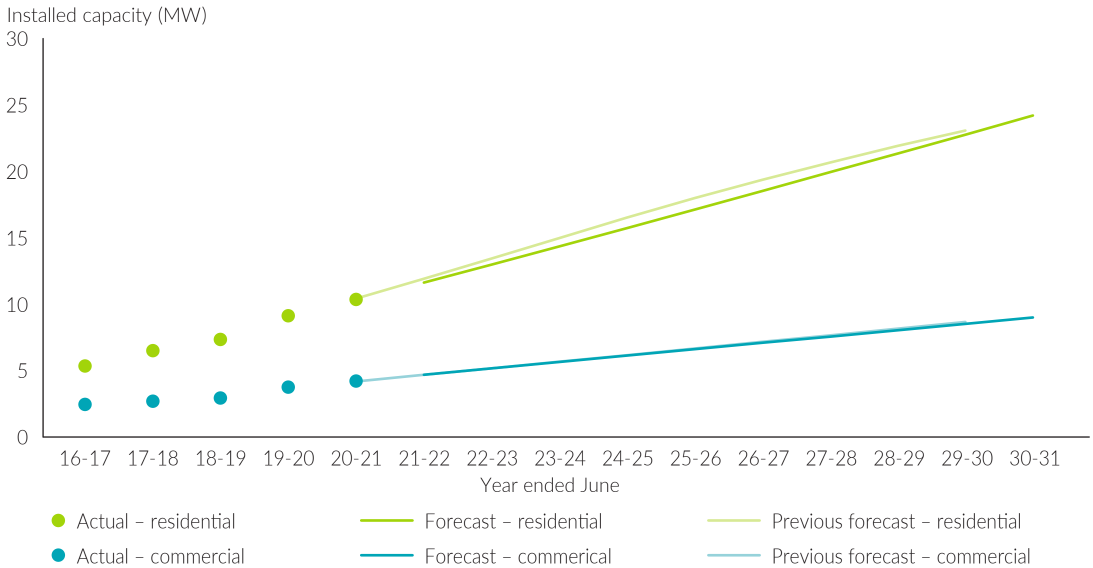
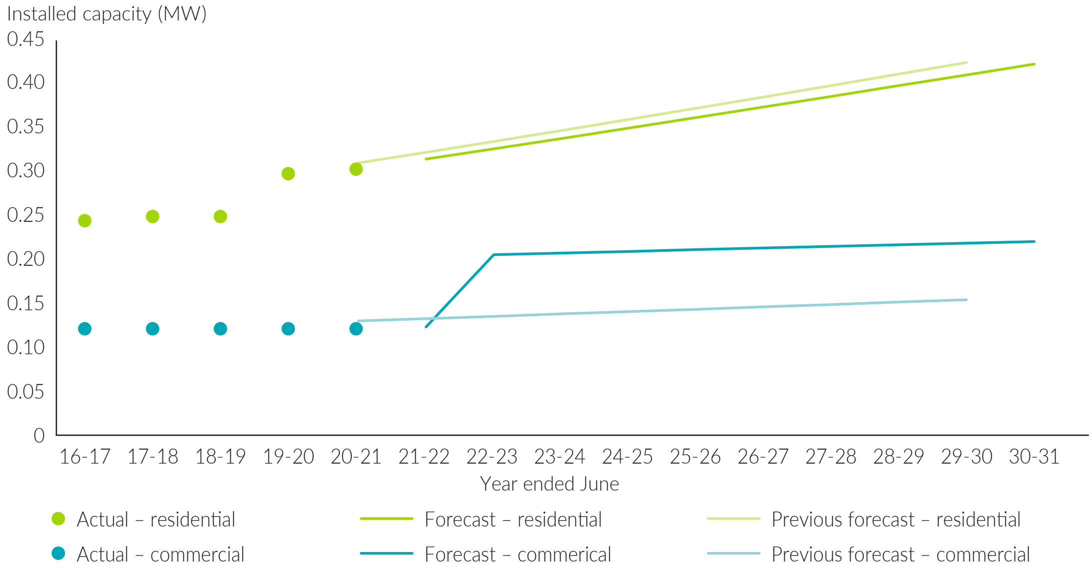


Figure 38: Historical and forecast distributed PV capacity, Tennant Creek, 2016-17 to 2030-31



A1.6.7 Behind-the-meter battery storage

Following feedback received in consultation, this NTEOR considers, for the first time, the impact of the uptake of behind-the-meter battery storage systems on forecast annual electricity consumption, maximum and minimum demand for each power system.

The battery contribution was accounted for by considering a set of battery charge/discharge profiles in conjunction with battery power installed capacity to give a half hourly time series capturing the impacts from behind-the-meter batteries. The charge/discharge profiles had the effect of smoothing out demand across the day and reducing maximum demand. The charge/discharge profiles and battery power forecasts were adopted from AEMO's work in the NEM. Specifically, Queensland charge/discharge profiles were used and the forecast of battery power from Queensland is 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 region approximately start from known installation levels.

Situations where control of a battery is determined by an aggregator, commonly referred to as a virtual power plant, were not considered.

A1.6.8 Electric vehicles

Following feedback received in consultation, this NTEOR also considers, for the first time, the impact of EV uptake on the annual electricity consumption and maximum and minimum demand forecasts.

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. EV charging profiles and vehicle uptake were adopted from AEMO's work in the NEM. Similar to behind-the-meter batteries, AEMO used Queensland forecast data and allocated it to each Territory region on a per capita basis, and applied a scaling factor to ensure forecasts in each Territory power system or node approximately start from known EV numbers.

A1.7 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 adopts for the NEM.[18] 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 electricity (consumption).

Traces are differentiated by:

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

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 (observed) trace to meet targets (demand trace has forecasts of technology components removed)
- pass 2 – reinstating forecasts of technology components and reconciling the time series to meet the forecast targets.

A1.7.1 Demand-side participation

There is currently no measurable demand-side participation instrument in use in Territory power systems. This is assumed to persist over the forecast outlook period.

18 See Electricity Demand Forecasting Methodology Information Paper, August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

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 RGPS, Tennant Creek power station (TCPS), CIPS, and KPS. Table 4 shows the future retirement dates used in the simulation and the units that have recently retired and therefore are not included in the 2021 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	3.99	31 December 2025
		4	3.99	31 December 2025
		5	3.99	31 December 2025
		6	5.23	31 December 2025
		7	5.23	31 December 2025
		8	5.23	31 December 2025
		9	12.83	31 December 2025
TCPS	Tennant Creek	1	1.14	31 December 2023
		2	1.14	Retired
		3	1.14	Retired
		4	1.14	Retired
		5	1.14	31 December 2023
		10	0.90	31 December 2028
		11	0.90	31 December 2028
		12	0.90	31 December 2029
		13	0.90	31 December 2029
		14	0.90	31 December 2030
CIPS	Darwin	1	30.02	31 December 2026
		2	30.02	31 December 2026
		3	30.02	Retired
		4	30.02	31 December 2027
KPS	Katherine	5	30.02	31 December 2027
		6	30.40	31 December 2027
		7	34.20	31 December 2029

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

While it was previously advised that Tennant Creek units 1 and 5 were retired, it is now advised they are still operational and available for dispatch.

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 new entrant that is highly likely to proceed as determined by the Commission. All the new entrant power stations and battery energy storage systems considered committed projects and included in the modelling are listed in Table 5. All 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	6 x 2.5 MW (however, 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)	22 January 2024
Batchelor 2 Solar Farm power station (Batchelor 2)	BSF Co Pty Ltd	Manton, Batchelor and Pine Creek	-	Single axis tracking (SAT) solar	10	31 December 2022
Batchelor Solar Farm power station (BSPS)	Eni Australia Limited	Manton, Batchelor and Pine Creek	-	SAT solar	10	30 September 2022
Manton Dam Solar Farm power station (MSPS)	Eni Australia Limited	Manton, Batchelor and Pine Creek	-	SAT solar	10	30 September 2022
Katherine Solar power station (KSPS)	Eni Australia Limited	Katherine	-	SAT solar	25	01 March 2022
Darwin BESS	Territory Generation	Darwin	-	BESS	32.6[2]	30 June 2023
CIPS 10	Territory Generation	Darwin	1	Gas	22.15	31 December 2023
RAAF Darwin	Assure Energy Asset Pty Ltd	Darwin	-	Fixed flat plate (FFP) solar	3.2	22 June 2023
Robertson Barracks	Assure Energy Asset Pty Ltd	Darwin	-	FFP solar	10	22 June 2023

1 Modelling assumes that most units will be fully available six months after the last start date provided by licenses.

2 The BESS does not supply energy in the supply adequacy assessment. However, it is expected to impact security requirements, which indirectly improves supply availability.

During the consultation period, feedback received from licensees and stakeholders indicated commissioning dates first provided to AEMO were more optimistic than expected, some even indicated to be fully operational at a date prior to publication of the 2021 NTEOR. In response to this feedback, most projects start dates were assumed to be delayed by six months for modelling purposes. The impact of this assumption on supply adequacy is expected to be immaterial.

Consistent with the 2020 NTEOR, 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 generator.[19] In addition to the Darwin BESS, CIPS 10 is also considered committed and was included in this year's assessment.

HCPS Co Pty Ltd advised 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 68.2 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 FFP and SAT solar projects were simulated using the System Advisor Model (SAM)[20] developed by 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. The reference year 2016-17 has been used in previous years, allowing for re-use of traces, but was supplemented by year 2015-16 for the 2021 NTEOR. 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.

A1.8.5 Exclusion of black start generators

Black start generators are not considered to contribute to supply capacity so they were not considered for the 2021 NTEOR. This is consistent with previous NTEOR supply adequacy assessments.

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

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

- unknown planned outages – or maintenance rates, are included in the model as annual percentages. These rates are based on information sourced from licensed generators. In the model, there is a distinction between unknown and known planned outages. Unknown planned outages are only added if the total of hours in known planned outages is less than the assumed annual maintenance rate of a generator. Furthermore, while known planned outages have a defined schedule, unknown planned outages are 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.[21] The timing of these outages was randomly allocated based on the assumed outage rates. These rates are 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 the 2020 NTEOR.

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

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

This results in outage rates that are more reflective of the likelihood a unit will be unavailable at a time when it is needed. Operational data from the three previous years is 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 power system. Similar to the 2020 NTEOR assessment, the historical data does not reflect the expected outcome due to the presence of one-off events. This is particularly true for the Frame 6 units at the CIPS in 2020-21. Units 1 and 6 had significant hours of unplanned outages that skewed the values. To calculate a more reasonable rate, AEMO ignored the 2020-21 financial year when calculating the rate for these two units.

21 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
CIPS 1–6	4.3	3.7
CIPS 7	8.9	6.6
CIPS 8 and 9	2.9	2.6
CIPS 10	-[1]	1.3[3]
Shoal Bay	2.0	3.3
HCPS	1.5[2]	1.5[2]
Weddell power station (WPS) 1–3	5.6	2.9
KPS 1–3	12.4	12.4
KPS 4	7.7	7.7
PCPS gas turbine (GT) 1 and 2	2.5[2]	0.5[2]
PCPS steam turbine (ST) 1	2.0[2]	2.0[2]

1 Unit was not present in 2020 NTEOR.
2 Values provided by the licensee rather than being calculated with historical data.
3 Based on GE's availability parameter for TM2500 generators; see https://www.ge.com/gas-power/products/gas-turbines/tm2500.

The outage rates for the thermal units in Alice Springs are shown in Table 7. OSPS units 5 to 14 were recently commissioned, and the calculated unplanned outages rates were very high due to specific commissioning activities. It would not be unreasonable to assume that these units would continue to fail at these high rates. However, AEMO considers that the outage rate proposed by the licensee is too low to allow for a likely transition period to more steady operation. To address this, an initial historical rate of 32.1% was applied in the first forecast year, and the rate gradually reduced to the proposed 1.0% after three years. RGPS units are still expected to continue to have a high rate of unplanned outages, due to the units approaching end of life, so the high outage rate was used in the supply adequacy assessment.

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
OSPS 1–3	7.8	6.3
OSPS 5–14	1.0[1]	32.1 to 1.0[2]
OSPS A	2.2	2.7
RGPS 3–9	44.4	44.1

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

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, so AEMO adopted the value used in the 2017-18 NTEOR, when these units had a larger breadth of operational history to determine the expected rate. Similarly to OSPS units 5 to 14, the newly commissioned TCPS units 19 to 21 were also modelled with a variable rate, starting at 4.2% in the first year of the outlook period, reducing to 1.0% after three years.

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
TCPS 1 and 5	n/a[1]	2.8
TCPS 10–15	0.5	1.1
TCPS 16–18	3.6	5.0
TCPS 19–21	1.0[2]	4.2 to 1.0[3]

1 Not modelled in the 2020 NTEOR.
2 Values provided by the participant rather than being calculated with historical data.
3 Variable rate discussed above.

A1.8.7 Generator auxiliaries

Generator auxiliaries refer to electricity used within a power plant and are expressed as a percentage of generation output during periods of full output. Consistent with the definition of system demand, as documented in Appendix A1.6.1, AEMO only considered the auxiliaries for the generators not owned by Territory Generation because the demand definition did not include the auxiliary loads of these sites. 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 are also assumed to have an auxiliary load rate of 0%, as is typical for the technology.

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

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

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 largest power systems may affect the dispatch availability and transmission capacity, and 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 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 Secure System Guidelines[22] are intended to document the present requirements, there is sufficient evidence[23] 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, but has simply sought to implement security requirements that best 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, inertia and voltage stability

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 System Control's Secure System Guidelines, Version 4.2.[22] AEMO understands 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 provisional aspect of PWC System Control's Risk Notifications, AEMO adopted in most instances the requirements present in the Secure System Guidelines, Version 4.2.

Based on advice previously provided by Territory Generation and PWC, both spinning and regulating reserve requirements may be breached in any 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 next section.

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.

22 See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.
23 Power and Water Corporation, Northern Territory Regulated Power Systems Biannual Report – January to June 2020. Internal operating scenarios spreadsheets.

Spinning reserve enables a power system to respond to a disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.[24]

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 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 simulation horizon.

The Secure System Guidelines also determine the spinning reserves' minimum regional figure. However, PWC System Control has amended 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.

Through these risk notifications, PWC System Control amended the spinning reserves minimum to 30 MW in Darwin-Katherine during the daytime (from 25 MW) and increased the minimum in Alice Springs to 11 MW at all times. PWC also increased the minimum spinning reserve requirement in Tennant Creek to 1.5 MW, but it has since been revised back to the regional figure set by the Secure System Guidelines. The spinning reserve minimum requirements used in the 2021 NTEOR are summarised in Table 11.

Table 11: Spinning reserve minimum requirement in the Northern Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	30.0 (day-time)
	25.0 (night-time)
Alice Springs	12.0 (day-time)
	7.0 (night-time)
Tennant Creek	0.8

24 Power and Water Secure System Guidelines, Version 4.2. See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

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 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, 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 projected 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 not maintaining the reserve requirements in order to avoid USE to some consumers may cause the operation to the overall power system to be less secure, and at an increased risk of a major event, including a system black in extreme circumstances. 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 reserves 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 2021 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.

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 critical failure (contingency). 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 into Channel Island. For modelling purposes, the inertia requirement is only enforced on the Darwin node of the Darwin-Katherine power system and not the Katherine node or the Manton, Batchelor and Pine Creek node
- 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	21.3
	WPS 1–3	82.6
Alice Springs	RGPS 3–5	11.9
	RGPS 6–8	9.0
	RGPS 9	39.4
	OSPS 1–3	22.3
	OSPS A	14.7
	OSPS 5–14	6.9

Although it is understood that the BESS in Alice Springs was installed primarily to compensate for the low inertia of the new OSPS reciprocating generators, PWC System Control has advised that the impact of the BESS in relation to its inertia contribution has not been quantified. Therefore, the BESS was excluded from contributing to the inertia requirement for modelling purposes.

However, it is understood Territory Generation's future BESS in Darwin 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 megawatt-seconds [MWs]). However, the BESS did not provide energy in the supply adequacy assessment.

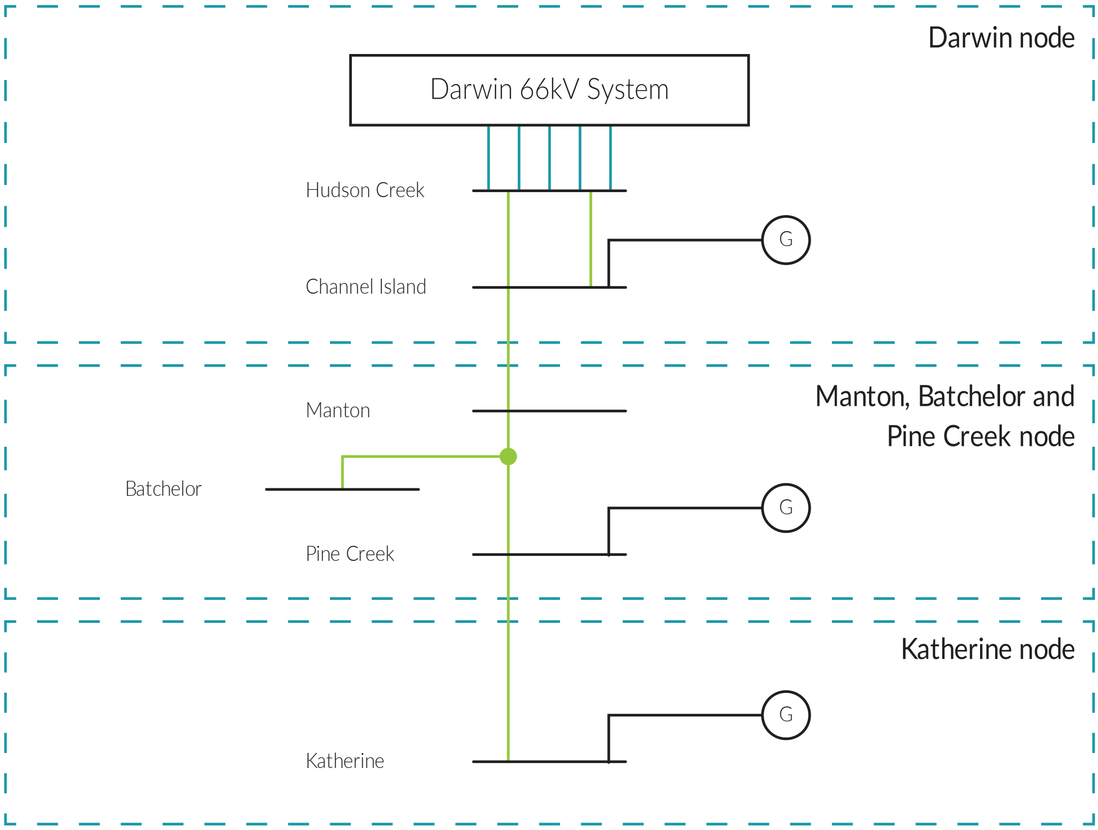
A1.9.5 Inter-regional limitations

The 2021 NTEOR supply adequacy assessment considered the Darwin-Katherine power system as three sub-regions or nodes, as shown against the single line diagram in Figure 39. Numerous limitations exist between the three regions, constraining the ability of generation in one region to meet the consumer demands in another. These include:

- thermal limitations on the transmission lines and transformers
- security limitations to ensure the secure operation of each region 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 megavoltamperes (MVA)[25] or approximately 105 MW. The thermal limit between the Manton, Batchelor and Pine Creek node and the Katherine node is assumed as the rating for the 132/22 kV Katherine zone substation, being 28.8 MVA[26] or approximately 28 MW.

Figure 39: Darwin-Katherine single line diagram



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.

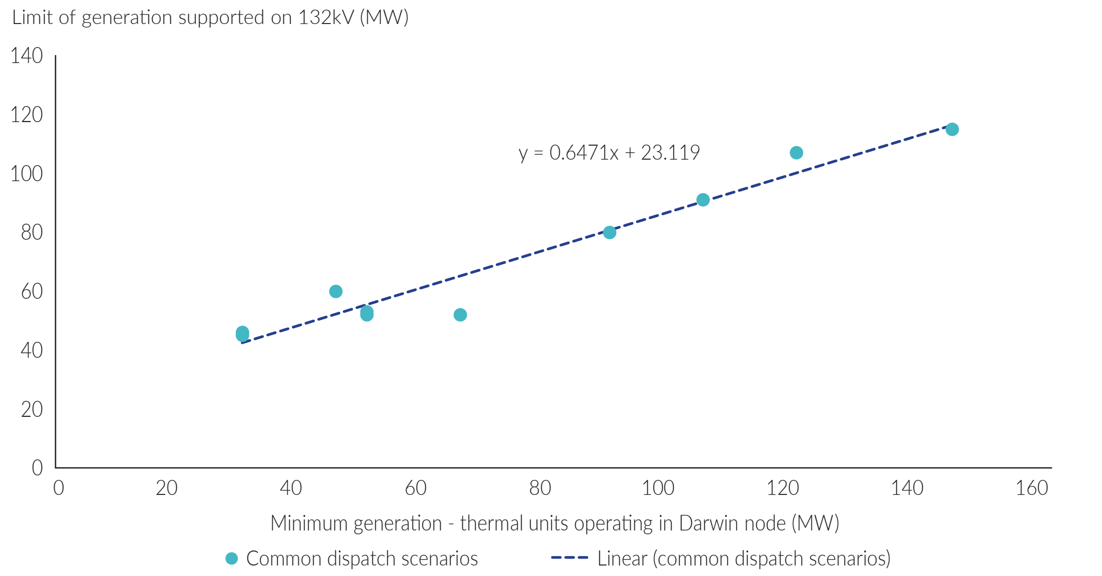
While numerous security considerations were included in the dispatch scenarios, a very strong relationship could be identified between constraints imposed on the generation limit for all generation south of Channel Island, and the sum of the minimum stable generation output of all thermal units operating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

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

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

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 40. When the Darwin BESS is installed, it was considered 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 40: 132 kV Darwin import limit relative to minimum 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 of 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 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 supply adequacy assessment in the 2021 NTEOR, AEMO assumed no contribution to generation supply from large-scale batteries, as all committed and existing batteries are understood to be intended for frequency control ancillary services and inertia services only. The new BESS announced in Darwin was not included as an energy provider in the supply adequacy assessment, and was only 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.

It is understood the Alice Springs BESS was installed primarily to provide network services. As these services are not relevant to the supply adequacy assessment, it was excluded altogether from this year's assessment.

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 are 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 scenario 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.[27] Weighted USE was then compared to the reliability standard of 0.002% used in the NEM simply for reference.[28]

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 electricity demand in a given region and financial year.

While the Territory Government has announced that the Territory will use a different form of reliability standard to the NEM and WEM,[29] there is uncertainty about how to calculate a value consistent with this standard. Since further advice is yet to be provided, reliability was calculated as USE only.

27 At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf.

28 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.

29 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 Table 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	31.60	30.02	Gas	1/01/1986	31/12/2026	36
CIPS 2	31.60	30.02	Gas	1/01/1986	31/12/2026	36
CIPS 4	31.60	30.02	Gas	1/01/1986	31/12/2027	36
CIPS 5	31.60	30.02	Gas	1/01/1986	31/12/2027	36
CIPS 6	32.00	30.40	Waste heat	1/01/1987	31/12/2027	35
CIPS 7	36.00	34.20	Gas	1/01/2000	31/12/2029	22
CIPS 8	42.00	39.90	Gas	1/01/2011	n/a	11
CIPS 9	42.00	39.90	Gas	1/01/2011	n/a	11
CIPS 10	23.57	22.15	Gas	31/12/2023	n/a	-
SBPS	1.123	1.123	Landfill gas	1/08/2005	n/a	16
HCPS	15.00	15.00	Gas	22/01/2024	n/a	-
WPS 1	34.00	32.20	Gas	1/02/2008	n/a	14
WPS 2	34.00	32.30	Gas	1/11/2008	n/a	13
WPS 3	34.00	32.30	Gas	1/03/2014	n/a	8
KPS 1	8.50	7.65	Gas	1/01/1987	31/12/2026	35
KPS 2	7.50	6.75	Gas	1/01/1987	31/12/2027	35
KPS 3	8.50	7.65	Gas	1/01/1987	31/12/2028	35
KPS 4	12.00	10.80	Gas	1/07/2012	n/a	9
PCPS GT1	10.20	9.70	Gas	1/07/2018	n/a	3
PCPS GT2	10.20	9.70	Gas	1/07/2018	n/a	3
PCPS ST1	6.00	5.80	Waste heat	1/06/1996	n/a	26
Darwin RAAF	3.20	3.20	Solar	22/06/2022	n/a	-
Robertson Barracks	10.00	10.00	Solar	22/06/2022	n/a	-
Batchelor 2	10.00	10.00	Solar	31/12/2022	n/a	-
BSPS	10.00	10.00	Solar	30/09/2022	n/a	-
KSPS	25.00	25.00	Solar	01/03/2022	n/a	-
MSPS	10.00	10.00	Solar	30/11/2022	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	10.70	10.165	Gas	1/10/2011	n/a	10
OSPS 2	10.70	10.165	Gas	1/10/2011	n/a	10
OSPS 3	10.70	10.165	Gas	1/11/2011	n/a	10
OSPS 5	4.40	4.14	Gas	1/01/2019	n/a	3
OSPS 6	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 7	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 8	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 9	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 10	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 11	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 12	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 13	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 14	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS A	3.90	3.71	Gas	1/01/2004	n/a	18
RGPS 3	4.20	3.99	Gas	1/01/1973	31/12/2025	49
RGPS 4	4.20	3.99	Gas	1/01/1973	31/12/2025	49
RGPS 5	4.20	3.99	Gas	1/01/1975	31/12/2025	47
RGPS 6	5.50	5.23	Gas	1/01/1978	31/12/2025	44
RGPS 7	5.50	5.23	Gas	1/01/1981	31/12/2025	41
RGPS 8	5.50	5.23	Gas	1/01/1984	31/12/2025	38
RGPS 9	13.50	12.83	Gas	1/11/1987	31/12/2025	34
Uterne Solar	3.88	3.88	Solar	1/08/2015	n/a	6

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	1.20	1.14	Gas	No data	31/12/2023	-
TCPS 5	1.20	1.14	Gas	No data	31/12/2023	-
TCPS 10	0.95	0.90	Gas	1/01/1999	31/12/2028	23
TCPS 11	0.95	0.90	Gas	1/01/1999	31/12/2028	23
TCPS 12	0.95	0.90	Gas	1/01/1999	31/12/2029	23
TCPS 13	0.95	0.90	Gas	1/01/1999	31/12/2029	23
TCPS 14	0.95	0.90	Gas	1/01/1999	31/12/2030	23
TCPS 15	3.90	3.71	Gas	1/01/2004	n/a	18
TCPS 16	1.50	1.42	Diesel	1/02/2008	n/a	14
TCPS 17	1.60	1.50	Diesel	14/12/2018	n/a	3
TCPS 18	1.60	1.50	Diesel	14/12/2018	n/a	3
TCPS 19	2.00	1.88	Gas	14/12/2018	n/a	3
TCPS 20	2.20	2.07	Gas	14/12/2018	n/a	3
TCPS 21	2.20	2.07	Gas	14/12/2018	n/a	3

A2.2 Projected unserved energy

The following tables show the projected USE for each Territory power system or 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
2021-22	0.0000	0.0001	0.0001	0.0003
2022-23	0.0000	0.0000	0.0001	0.0001
2023-24	0.0001	0.0000	0.0000	0.0001
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	0.0001	0.0001
2027-28	0.0021	0.0105	0.0211	0.0336
2028-29	0.0161	0.0222	0.0590	0.0974
2029-30	0.0502	0.1112	0.1864	0.3478
2030-31	0.1447	0.1945	0.3040	0.6433

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

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2021-22	0.0000	0.0001	0.0001	0.0003
2022-23	0.0000	0.0000	0.0001	0.0001
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	0.0001	0.0001
2027-28	0.0018	0.0106	0.0240	0.0365
2028-29	0.0126	0.0199	0.0671	0.0996
2029-30	0.0384	0.1007	0.2136	0.3527
2030-31	0.1139	0.1723	0.3566	0.6428

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
2021-22	0.0000	0.0000	0.0000	0.0000
2022-23	0.0000	0.0000	0.0000	0.0000
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	0.0000	0.0000
2027-28	0.0000	0.0000	0.0000	0.0000
2028-29	0.0000	0.0062	0.0068	0.0131
2029-30	0.0000	0.0153	0.0100	0.0253
2030-31	0.0000	0.0913	0.0360	0.1273

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

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2021-22	0.0001	0.0000	0.0001	0.0002
2022-23	0.0002	0.0000	0.0000	0.0002
2023-24	0.0002	0.0000	0.0000	0.0002
2024-25	0.0002	0.0001	0.0000	0.0003
2025-26	0.0002	0.0000	0.0000	0.0002
2026-27	0.0004	0.0000	0.0001	0.0005
2027-28	0.0043	0.0107	0.0000	0.0150
2028-29	0.0499	0.0463	0.0000	0.0962
2029-30	0.1648	0.2216	0.0000	0.3864
2030-31	0.4447	0.4110	0.0000	0.8557

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

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2021-22	0.0008	0.0038	0.0086	0.0131
2022-23	0.0004	0.0016	0.0019	0.0039
2023-24	0.0001	0.0001	0.0012	0.0015
2024-25	0.0000	0.0000	0.0015	0.0015
2025-26	0.0001	0.0000	0.0010	0.0011
2026-27	0.0002	0.0006	0.0156	0.0164
2027-28	0.0000	0.0006	0.0192	0.0199
2028-29	0.0001	0.0001	0.0038	0.0040
2029-30	0.0001	0.0003	0.0036	0.0040
2030-31	0.0001	0.0019	0.0349	0.0369

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

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2021-22	0.0000	0.0000	0.0000	0.0000
2022-23	0.0000	0.0000	0.0000	0.0000
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	0.0000	0.0000
2030-31	0.0000	0.0000	0.0001	0.0001

Appendix A3: Forecasting performance

AEMO has prepared this forecasting performance assessment to determine the accuracy of the demand forecasts in AEMO's 2020 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. Specifically, for the 2021 NTEOR, AEMO has implemented a machine learning algorithm to derive a model with good fit and strong predictive power.

In addition, AEMO identified and implemented an improved method for dealing with model residuals in the half-hourly simulation engine to better account for residual distributions at the time of maximum and minimum events.

A3.1 Annual system consumption

Table 25 compares forecast and actual annual system consumption for each of the three Territory power systems in 2020-21. Actual annual system consumption for all power systems was lower than the corresponding forecasts.

Table 25: Comparison between forecast and actual annual system consumption for 2020-21

Power system	2020-21 AEMO forecast (GWh)	2020-21 actual (GWh)	Difference (%)
Darwin-Katherine	1503.2	1465.3	2.6
Alice Springs	211.6	202.1	4.7
Tennant Creek	31.5	29.9	5.5

The forecast system consumption value for Darwin-Katherine in 2020-21 was 2.6% greater than the observed value. Over this period, the total installed capacity of distributed PV systems in the Darwin-Katherine power system increased from 77.9 MW to 88.0 MW. This increase in distributed PV exceeded the installed capacity forecast value by 2.9 MW and partly contributed to the lower-than-expected observed system consumption value for Darwin-Katherine.

In Alice Springs, 2020-21 saw a 3.4% decrease in annual system consumption from the previous year. The forecast annual system consumption for Alice Springs was 4.7% greater than the observed value. The 2020-21 financial year was considered a relatively mild year with regards to maximum daily temperatures over the summer period, particularly when compared with the preceding years. In 2020-21, Alice Springs recorded only 11 days that exceeded 40° celsius (C), while in the 2017-18, 2018-19 and 2019-20 financial years, there were 26, 43 and 30 days that exceeded 40°C, respectively. Consequentially, the milder temperatures observed in 2020-21 contributed to reducing the overall consumption recorded in Alice Springs.

In Tennant Creek, 2020-21 saw a decrease in annual system consumption from the previous year. The forecast for Tennant Creek was 5.5% greater than the observed value. The difference in values was largely attributed to the connection of a mining development not materialising. Without this block load assumption, the Tennant Creek forecast would have been only 1.6% less than the observed value.

A3.2 Maximum demand

Table 26 compares forecast and actual maximum system demand for each Territory power system in 2020-21.

The actual maximum system demand in the Darwin-Katherine power system was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 0.27%[30] higher than the actual and judged by AEMO to be reasonable.

The actual maximum system demand in the Alice Springs power system was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 1.88% higher than the actual and 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 10.45% higher than the actual. The higher forecast was due to the expectation that the Northern Gas Pipeline infrastructure would be drawing power (0.625 MW) from the system during summer and a new mine development would be drawing power (0.3 MW) from July 2021 onwards, which both did not occur. The block load pertaining to the new mine development is no longer considered in the forecasts. Accounting for this, the forecasted value was judged by AEMO to be reasonable.

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

Power system	2020-21 forecast (MW)			2020-21 actual (MW)	Actual timestamp	Actual dry-bulb temperature (°C)
	POE90	POE50	POE10			
Darwin-Katherine	270.3	277.4	286.6	285.8	Monday, 16 November 2020 19:00	32.3
Alice Springs	48.9	51.2	53.8	52.8	Monday, 30 November 2020 17:30	40.4
Tennant Creek	7.8	8.2	8.6	7.1	Friday, 13 November 2020 16:00	42.5

A3.3 Minimum demand

Table 27 compares forecast and actual minimum system demand for each Territory power system in 2020-21.

The actual minimum system demand for Darwin-Katherine was above the 10% POE forecast. The 10% POE forecast was 8.28% lower than the actual. While no clear explanation can be identified, AEMO has made improvements to the forecasting methodology, as noted in this section, which in this case could improve the minimum demand forecasts.

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 4.28% lower than the actual and judged by AEMO to be reasonable.

The actual minimum system demand in the Tennant Creek power system was below the 90% POE forecast. The 90% POE forecast was 23.08% higher than the actual. The higher forecast was due to the expectation of a new mining development. This site was forecast to start on July 2021 and expected to draw 0.3 MW of power at the time of minimum

30 The percentage is estimated by (Forecast (POE10) – Historical)/Historical * 100. For example. The difference between historical and forecast in Darwin-Katherine is (286.57 – 285.79) / 285.79 * 100 = -0.27%.

demand. This site did not come online and is no longer considered in the forecasts. Accounting for this, the forecasted value was judged by AEMO to be reasonable.

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

Power system	2020-21 forecast (MW)			2020-21 actual (MW)	Actual timestamp	Actual dry-bulb temperature (°C)
	POE90	POE50	POE10			
Darwin-Katherine	67.5	71.9	76.4	83.2	Sunday, 16 May 2021 12:00	28.4
Alice Springs	7.3	8.3	9.2	8.7	Sunday, 11 October 2020 11:00	23.4
Tennant Creek	1.6	1.7	1.8	1.3	Friday, 7 May 2021 3:00	17.2

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
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
FFP	fixed flat plate
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 Dam Solar Farm power station
MVA	megavoltamperes
MW	megawatt, 1MW = 1 million watts
NEM	National Electricity Market
NTEOR	Northern Territory Electricity Outlook Report
OSPS	Owen Springs power station
Outlook period	2021-22 to 2030-31
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
WEM	Western Australia Wholesale Electricity Market
WPS	Weddell power station