2025 Thermal Audit

November 2025

Final Report

A report for the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The review is undertaken in the exercise of AEMO's functions to maintain and improve power system security under section 49(1)(e) of the National Electricity Law (NEL) as it is focussed on ensuring secure operation of the NEM by considering generator capability and infrastructure resilience. The purpose of this publication is to outline the evolving role of thermal generation in the NEM and its role in relation to management of power system security in the National Electricity market.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of participants and original equipment manufacturers in providing data and information used in this publication.

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Abbreviations

Abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
AVP	AEMO Victorian Planning
AVR	automatic voltage regulator
BECCS	bioenergy with carbon capture and storage
BESS	battery energy storage system
CCGT	combined cycle gas turbine
CEMS	continuous emissions monitoring system
DPV	distributed photovoltaic (rooftop solar)
EPL	Environmental Protection Licence
GFM	grid-forming
GPS	Generator Performance Standard
GPSRR	*General Power System Risk Review*
GT	gas turbine
GW	gigawatt/s
GWs	gigawatt second/s
IBR	inverter-based resource/s
IEA	International Energy Agency
ISP	*Integrated System Plan*
kL	kilolitre/s
kt	kilotonne/s
kW	kilowatt/s
L	litre/s
L/h	litres per hour
L/s	litres per second
LOR	Lack of Reserve
Ltd	Limited
ML	megalitre/s
MPa	megapascal/s
MSOL	minimum stable operating level
Mt	million tonnes
Mtpa	million tonnes per annum
MVA	megavolt ampere/s
MVAr	megavolt ampere/s reactive
MW	megawatt/s
MWe	megawatt/s electric

Abbreviation	Meaning
MWh	megawatt hour/s
MWs	megawatt second/s
NEM	National Electricity Market
NS	non-scheduled (generation)
OCGT	open cycle gas turbine
OEM	original equipment manufacturer
PADR	Project Assessment Draft Report
PS	power station
Pty	Proprietary
PV	photovoltaic
RIT-T	Regulatory Investment Test for Transmission
SCADA	supervisory control and data acquisition
SRAS	system restart ancillary services
SSSP	System Strength Service Provider
syncon	synchronous condenser
TJ	terajoule/s
TJ/h	terajoules per hour
TNSP	transmission network service provider
TTHL	trip to house load
VRE	variable renewable energy

1 Introduction

The National Electricity Market (NEM) power system is undergoing a major transformation in the way energy is produced and used, with a significant increase in renewable generation, particularly variable, inverter-connected, decentralised generation, across transmission and distribution networks. In the context of this transition, the reliability, flexibility and service provision from the fleet of thermal generators is increasingly critical – for supporting reliable and secure power system operations, as well as enabling the transition itself.

This 2025 review of the NEM thermal fleet focuses on understanding the flexibility and reliability of thermal generators and the evolving role of thermal power generation, and how this influences power system operability. The review is of the thermal generators with capacities above 30 megawatts (MW), covering performance in the period from 2019-20 to 2024-25 and evaluation of capability and flexibility. Generators were categorised by fuel and technology type, grouped by region, and assessed based on capacity factor, utilisation and flexibility characteristics.

Eight stations were identified for detailed study; this included questionnaires, on-site and virtual meetings. Additionally, a further 17 stations were sent questionnaires, with responses received from the majority. Several original equipment manufacturers (OEMs) for thermal generation technologies also provided valuable information to support the review. This engagement aided understanding of generators' current capabilities, and planned and potential changes and upgrades. The review also provided an opportunity to raise awareness regarding current, future and potential operational needs of the NEM power system.

High level findings and insights from the 2025 Thermal Audit are shared in this report, to help build general industry understanding and awareness regarding:

- the relationship between thermal generator minimum load capability and system wide minimum system load management,
- station specific risks and opportunities including potential for two-shifting, seasonal lay-ups, restart capability and synchronous condenser conversion, and
- the benefit of ongoing engagement by AEMO with OEMs and participants to understand how site-specific risks and opportunities influence the security and operability of the NEM.

Previous key studies that informed this audit include an internal review in 2018 and the 2020 coal plant reliability review[1].

1.1 Definition adopted for this report

For the purpose of this report, the reference to 'thermal power plants' includes only those thermal generation technologies at the point of connection in the NEM of 30 MW or greater. Non-scheduled generation was excluded from this review to avoid distortion in the analysis as these generators have less influence over their output as a response to price signals and do not have to submit bids.

[1] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-elical-assessment-of-ageing-coal-fired-generation-reliability.pdf.

1.2 Thermal Audit objectives

The review is undertaken in the exercise of AEMO's functions to maintain and improve power system security under section 49(1)(e) of the National Electricity Law (NEL) as it is focused on ensuring secure operation of the NEM by considering generator capability and infrastructure resilience. The review is designed to support AEMO's development of an operational strategy for management of the existing thermal fleet and help inform a range of work programs across AEMO.

The 2025 Thermal Audit is a review of the capabilities of thermal power plants, and a detailed review of a selection of key thermal power plant. This detailed review involved administering questionnaires to, and subsequent discussion with, operators to understand generators' current capabilities, including planned changes, potential changes and upgrades and how they may influence the operability of the NEM.

1.3 Approach to the study

The 2025 Thermal Audit was undertaken in three key stages.

1. Source and review background information

- Evaluate at a high level the capability of the existing thermal power plants to meet operational requirements, including risks and opportunities with respect to capacity, capabilities, reliability, flexibility, start times, minimum generator levels, and efficiency.
- Undertake a desktop review of system operational needs.

2. Engage with key station owners and OEMs

- Develop criteria for selection of stations for in-depth analysis and issue of questionnaires.
- Engagement with OEMs including issuing questionnaires.

3. Summarise and report on key findings

- Identify key findings across the categories of the NEM thermal generation:
  - black coal sub-critical coal plant
  - brown coal sub-critical plant
  - black coal super-critical plant
  - large gas turbine plant (typically unit size >100 MW)
  - smaller gas turbine plant (including units <30 MW that are aggregated to >30 MW at the point of connection), and
  - thermal gas plant, reciprocating engines, biomass plant and landfill/sewage gas plants that are >30 MW at the point of connection (summarised as 'Other plant').
- Identify the major OEMs for boilers, steam and gas turbines in the NEM and also new or repurposed synchronous condensers, issue questionnaires and produce summaries of information received.
- Summarise and report on findings, risks and opportunities.

1.4 Acknowledgement

AEMO would like to acknowledge and thank all Participants and OEMs that provided input to the development of the 2025 Thermal Audit. AEMO would also like to thank engineering consultants engaged by AEMO, AEP Elical, who assisted with the review.

2 Overview of thermal power plants

2.1 Key thermal power plants

The following types of thermal power plant are referred to in this report:

- The **coal- and gas-fired thermal steam plants** are Rankine cycle plants that comprise either coal, gas, liquid or biomass fuel fired in a boiler to produce high pressure steam that is used to run a steam turbine generator that produces power. The NEM fleet comprises both sub-critical[2] and more modern super-critical coal plants.
- The **open cycle gas turbine (OCGT)** plants are Brayton cycle plants that comprise gas turbine/generator units that produce power. The gas turbines are normally fired on gas, with diesel often used as back-up fuel. This technology is sometimes referred to as a simple cycle. Two types of gas turbines are commonly used:
  - Aeroderivative gas turbines are generally based on aircraft engines and are smaller and lighter. They generally have smaller generation capacity with fast start times, relatively high ramp rates and can handle load changes more quickly when compared to industrial gas turbines. The output typically ranges from 20 MW to 50 MW.
  - Industrial gas turbines are of a heavier and larger frame design and are typically classified as E-class, F-class and H-class ranging in output from 40 MW up to 500 MW.
- The **combined cycle gas turbine (CCGT)** plants combine a gas turbine (Brayton cycle) and a steam turbine (Rankine cycle). The gas turbine is usually gas-fired, generating two-thirds of the electricity and producing hot exhaust gases which are sent to a heat recovery steam generator (HRSG). The HRSG uses this waste heat to produce steam to power a steam turbine, generating the remaining one-third of electricity. CCGT plants driving a single generator are called single shaft, while each turbine having its own generator is called multi-shaft. In the NEM, CCGTs are of both single and multi-shaft configurations.
- **Reciprocating engines** are a type of internal combustion engine. The fuel is usually distillate or diesel (and thus more expensive) but engines can also be designed to operate on gas. Reciprocating engines are usually classified as medium speed or high speed. Medium speed engines operate at 500-750 rpm and typically range in output from 4-18 MW. High speed engines operate at 1,000-1,500 rpm with a typical output below 4 MW. A reciprocating engine power station typically consists of multiple engines to make up the total station generating capacity.

2.2 Thermal power plant makeup

The 2024-25 combined generation capacity of the thermal power plant was 35 gigawatts (GW) in comparison to the maximum operational demand for the NEM of approximately 34 GW and an underlying average demand of approximately 24 GW. The installed generating capacity breakdown by technology and fuel type for the thermal power plant is shown in **Figure 1**.

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[2] Sub- and super-critical refer to the steam pressure. This is higher for super-critical plant where there is no transition from water to steam. There are minor differences in technology, and the super-critical plants tend to have higher efficiency.

Figure 1 NEM thermal power plant breakdown by technology (% of 35 GW), 2024-25

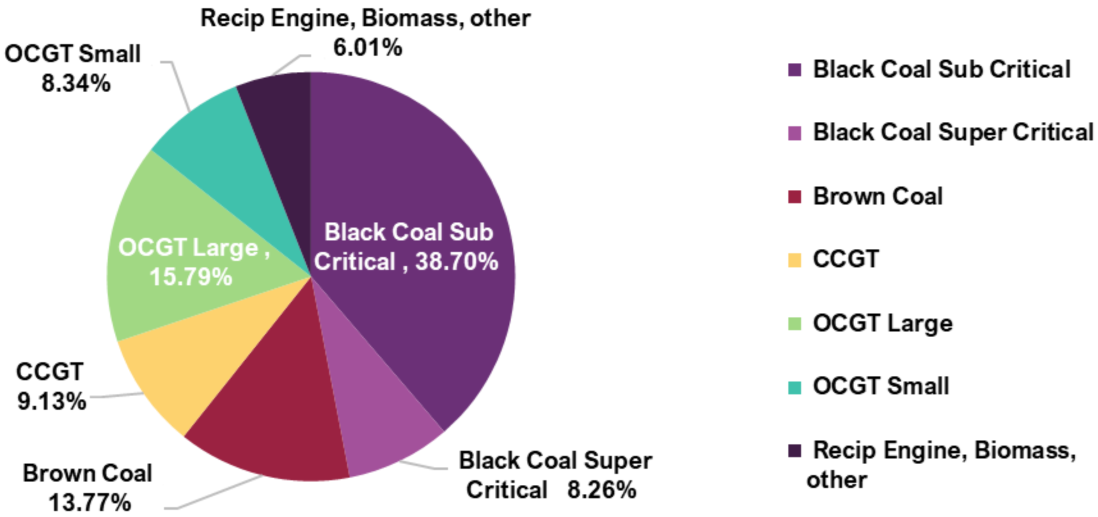
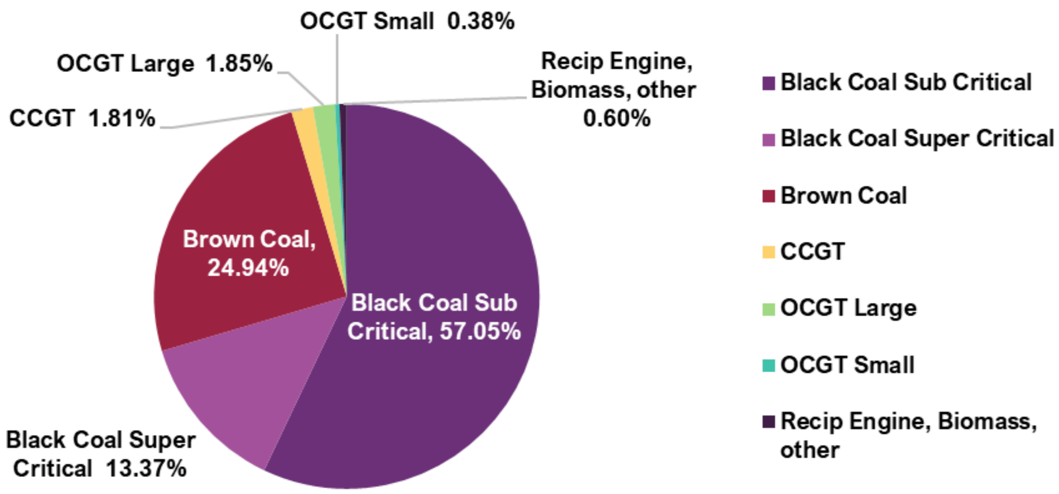


Figure 2 shows an indicative breakdown of the energy generated by each technology type in the NEM for stations over 30 MW at point of connection. Coal-fired stations contribute close to 95% of the over 30 MW NEM thermal fleet generated energy, and gas turbine plants around 4%. Other scheduled plants contribute only around 1%.

Overall, total NEM generation in 2024-25 was approximately 190 terawatt hours (TWh), of which the total thermal fleet (including plants of <30 MW) contributed approximately 127 TWh (67%), while the fleet over 30 MW contributed approximately 63%.

Figure 2 NEM thermal generation energy breakdown by technology (% of 127 TWh), 2024-25

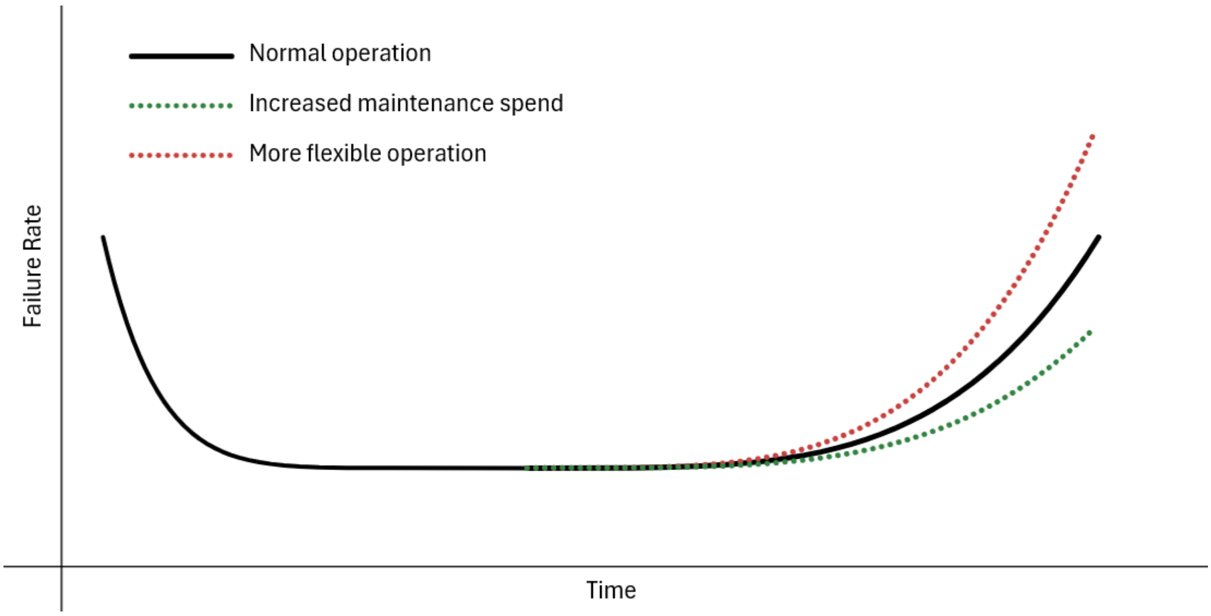


These figures show that in 2024-25, coal-fired plants make up over 50% of the installed thermal plant capacity and produced over 95% of the energy from thermal generation. As coal-fired power stations retire in the coming years and the energy and services they provide are replaced by other energy sources, the reliability and availability of any remaining coal-fired stations may be crucial to the effective operation of the power system. This highlights an increasing need for asset management programs to achieve and maintain (or improve) the remaining plants' availability, and evaluation of relevant risks and opportunities through AEMO bodies of work such as the *Transition Plan for System Security*[3].

2.3 Flexible operations

There is a known relationship between increased flexible operations (associated with increased pressure and temperature changes) and maintenance expenditure to maintain present levels of availability. Flexible operation is expected to bring forward the upward curve in the well-known bathtub curve of plant breakdowns and also may introduce new failure modes throughout the plant life cycle (noting the single line in **Figure 3** is a composite of many individual lines for different components of the power station).

Figure 3 Example bathtub curve



2.4 Anticipated coal retirements

The decommitment scenarios of coal generators in AEMO's 2024 *Integrated System Plan* (ISP)[4] provide three forecasts for closure of the thermal coal fleet, as illustrated in **Figure 4**. The *Step Change* scenario shows a relatively steep closure of thermal generation, and is the most widely used scenario in other publicly available studies and for AEMO modelling purposes[5].

The closure of coal generators will have a substantial impact on the NEM, and the loss of capability will be multi-dimensional, as the coal generators provide:

- on-demand dispatch capacity to meet peak requirements,

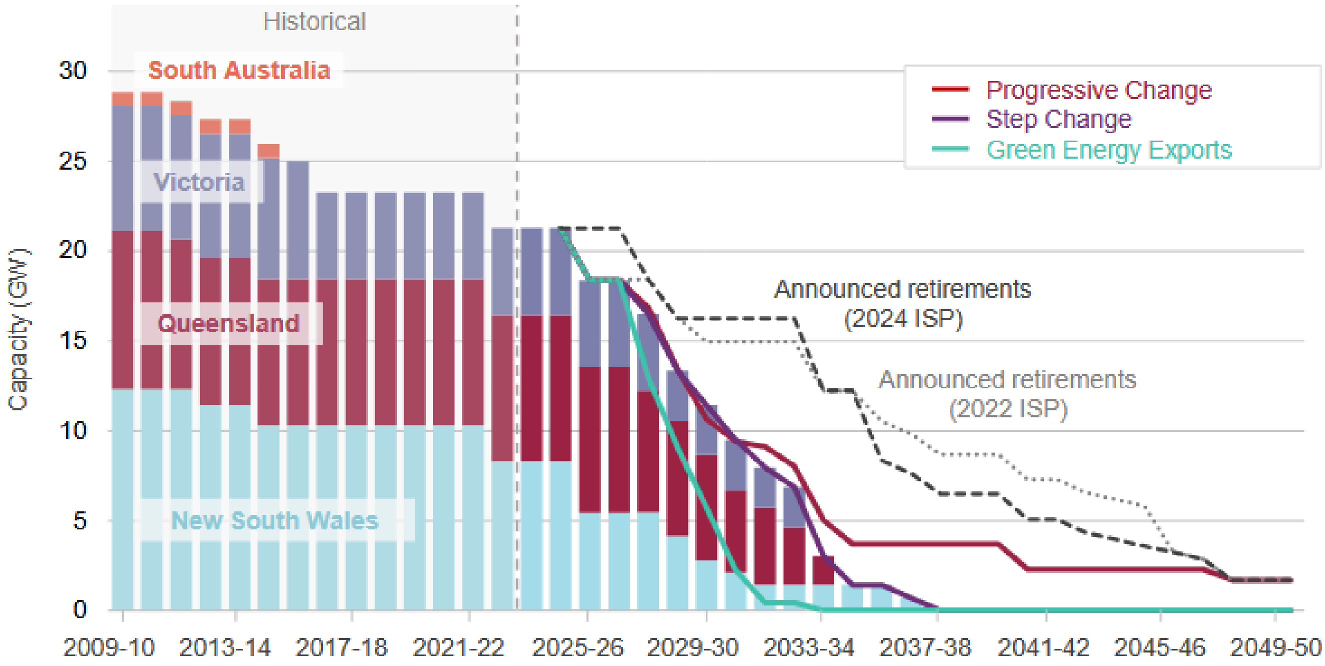
[3] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning.

[4] See https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en (page 10).

[5] AEMO's Draft 2026 ISP is set to be released in December 2025.

- substantial amounts of on-demand dispatchable energy, and
- inertia and system strength as a by-product of market participation for the provision of energy.

Figure 4 Decommitment scenarios of coal generators



Source: 2024 ISP.

AEMO has identified the combinations of generations required for system strength purposes by state, largely relying on coal-fired units in Victoria, New South Wales and Queensland[6].

[6] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice.

3 Thermal power plant operation and performance

The 2025 review concentrated on actual performance over the six financial years between 2019-20 to 2024-25. It considered trends in operational performance as well as generators' availability and flexibility. AEMO excluded non-scheduled generation from this review to avoid distortion in the analysis, as these generators have less influence over their output as a response to price signals and do not have to submit bids. The review covered individual stations and summarised these by technology and state, with overall NEM-wide results reflected below.

3.1 Capacity factors

The output of key stations over time was taken from the dispatch SCADA summary data in the AEMO online archives. This data was then used to calculate capacity factors for 2020-21 to 2025-26, shown in **Figure 5** for power stations identified as significant to the 2025 NEM Thermal Audit. While it covers much of the NEM capacity (megawatts) and generation (megawatt hours), caution is required to extend this to be representative of a state or technology's overall performance.

3.1.1 Coal-fired station capacity factors

The capacity factors of the stations for the last six financial years were compared by plant type and are summarised as:

- black coal – 62% on average, and
- brown coal – 75% on average.

This is compared to the last three financial years, summarised as:

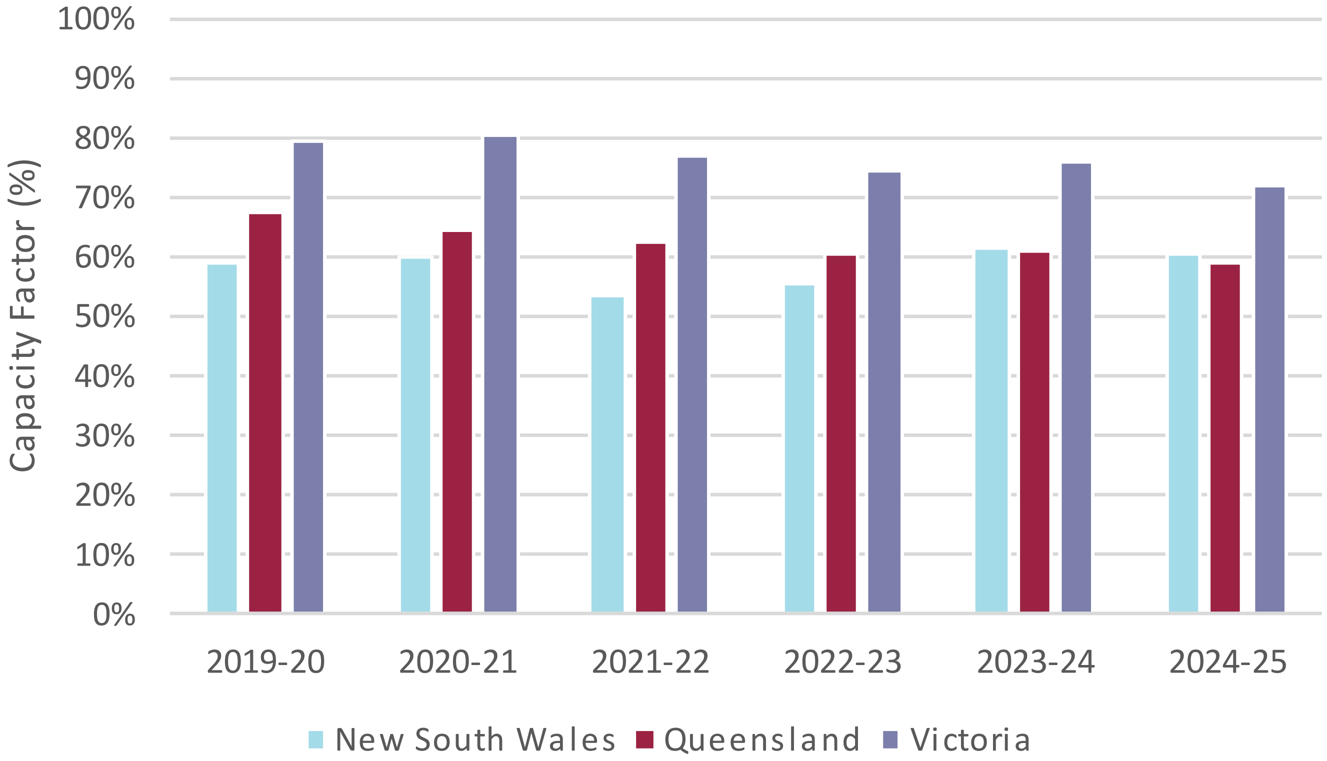
- black coal – individual units up to approximately 85%, but some units down to 20% due to major breakdowns and subsequent outages, and
- brown coal – in the range 50% to 85%.

AEMO conducted an analysis to understand if the capacity factors of coal stations in each of the regions were showing any trends from 2019-20 to 2024-25. **Figure 5** shows the graph from this analysis.

Queensland and Victorian stations have shown a reduction of approximately 9% since 2020, but the decline rate has slowed in the last three years.

The capacity factor for New South Wales has been relatively constant over this period, however this may have been driven by the closure of Liddell with the last unit taken out of service in April 2023, which would explain the slight increase since the 2023 financial year. New South Wales may have otherwise seen a similar reduction to the other states.

Figure 5 New South Wales, Queensland and Victoria coal fleet combined capacity factors, 2019-20 to 2024-25



3.1.2 Gas turbine capacity factors

The capacity factors of the stations for the last six financial years were compared by plant type and are summarised as:

- CCGT – 27% on average, and
- OCGT – 5% on average and all always below 30%.

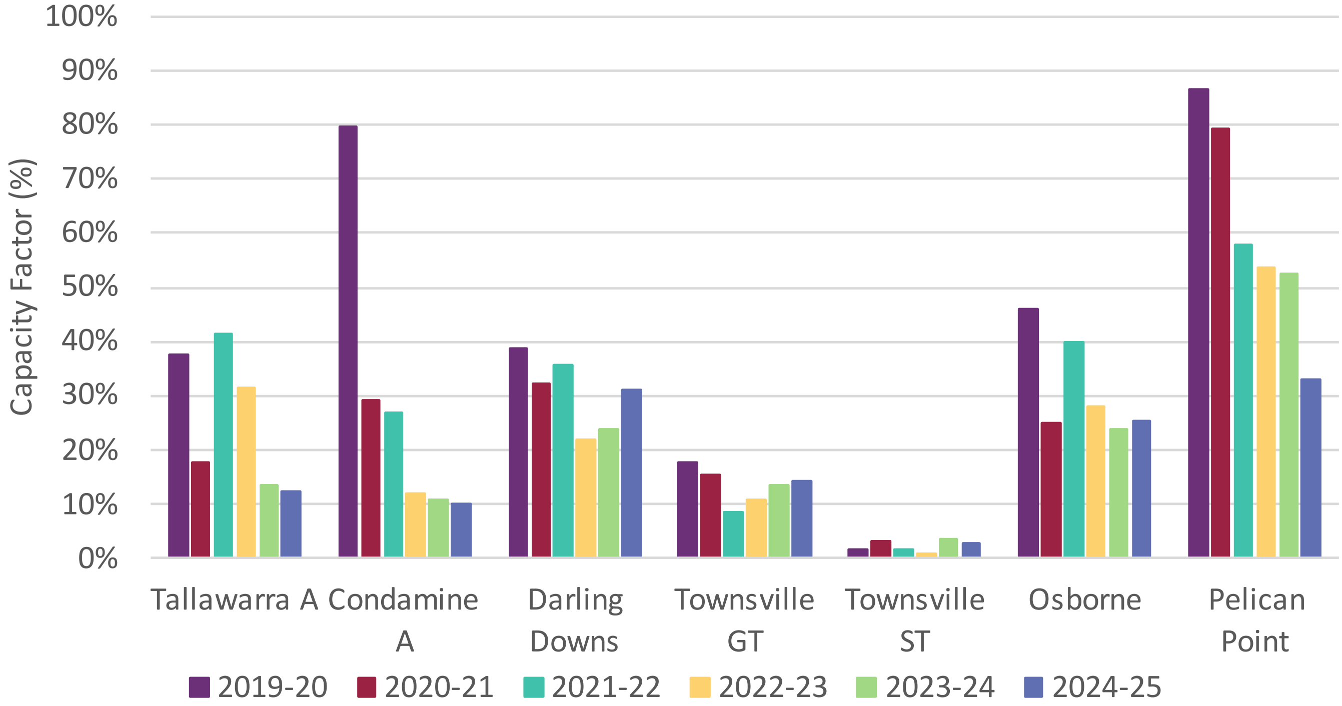
This is compared to the last three financial years, summarised a:

- CCGT – ranged from 10% to 50%, and
- OCGT – generally below 10% capacity factor.

There has been a general reduction in CCGT output over the last six years, and the Townsville plant operated as an OCGT before recent conversion to add additional service as a synchronous condenser (syncon).

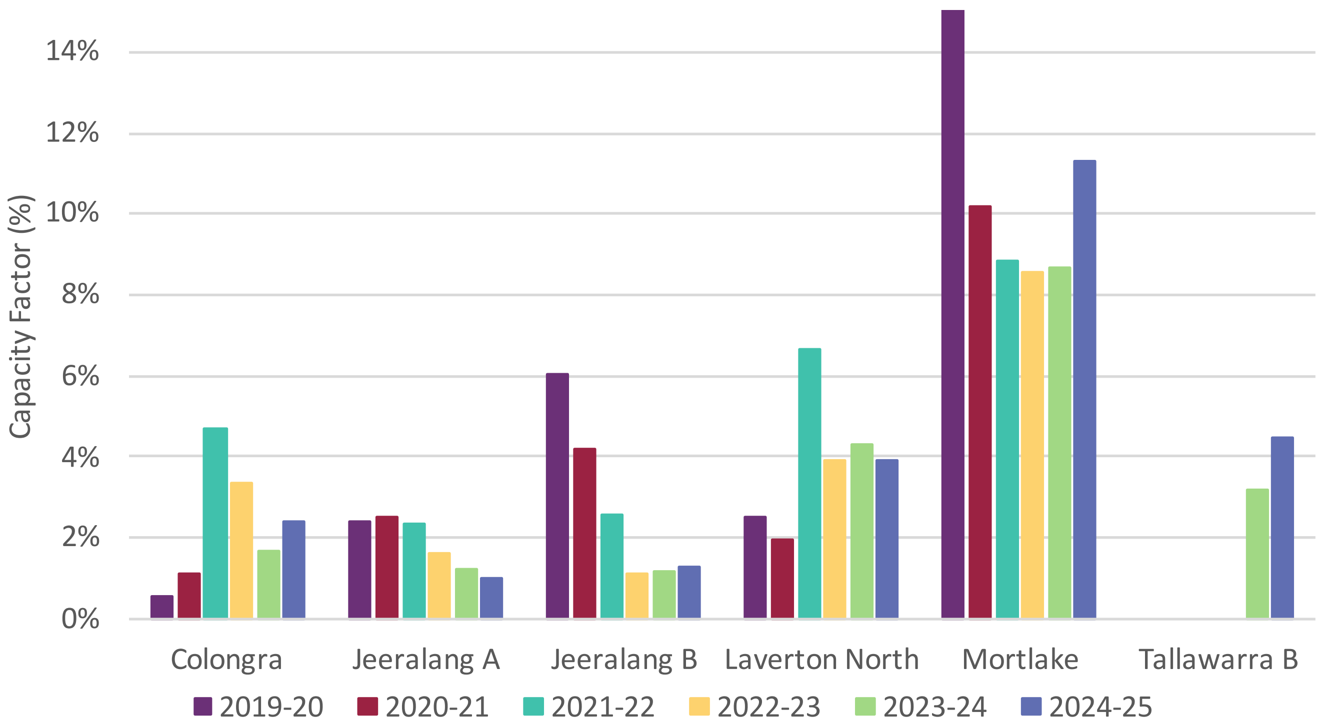
Capacity factors are shown by configuration in **Figure 6** and **Figure 7**.

Figure 6 Combined cycle gas turbine station capacity factors, 2019-20 to 2024-25



GT: gas turbine. ST: steam turbine.

Figure 7 Open cycle gas turbine station capacity factors, 2019-20 to 2024-25

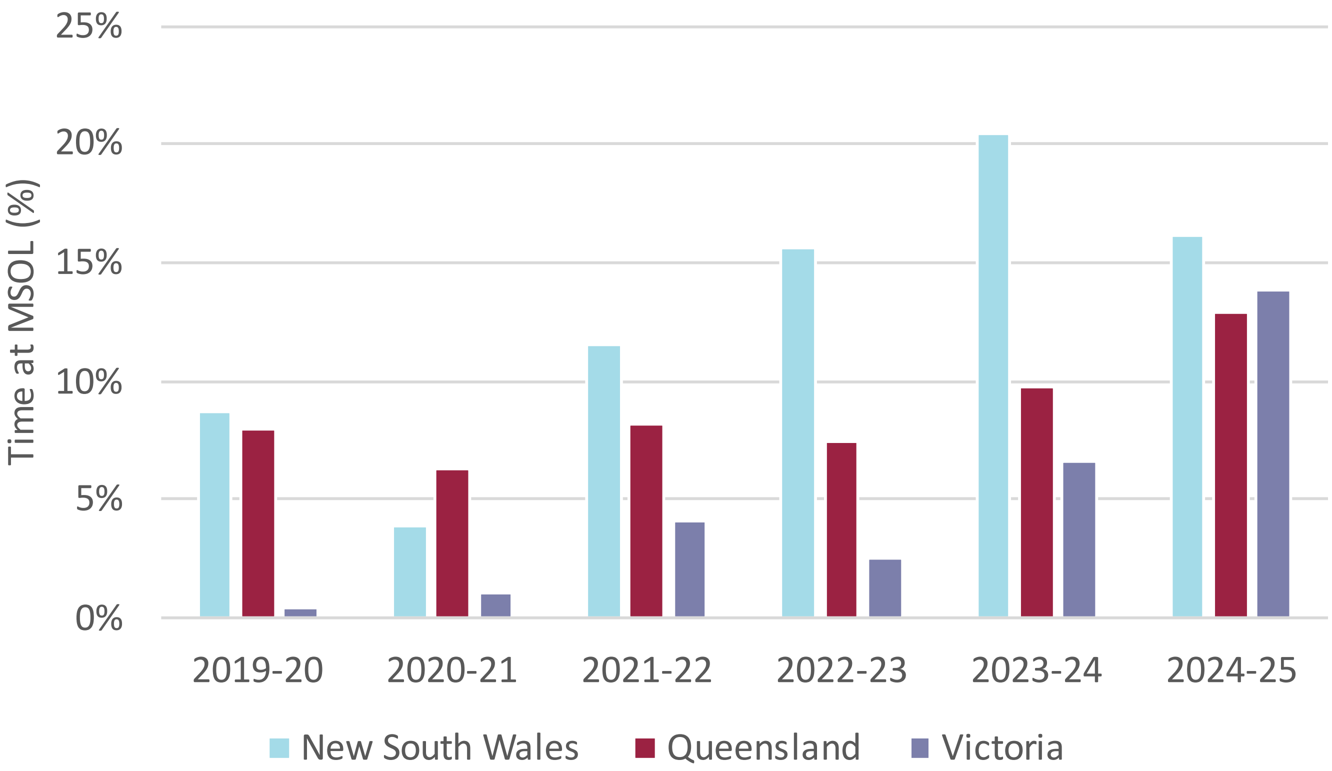


3.2 Coal-fired station minimum stable operating level utilisation

The dispatch SCADA summary data was also used to illustrate the percentage of time coal-fired stations spent operating at minimum stable operating levels (MSOLs). AEMO analysed raw output over time data in conjunction with the MSOL values provided in station responses to determine how long plants operated at MSOL.

Although the MSOL value for a number of generators has changed during this period, which would tend to reduce the number of hours in the later years, there is a clear trend to more operating hours at MSOL. This is particularly true for the Victorian brown coal stations, where the time at (or around) MSOL increased from less than 1% of operating hours in 2019-20 to 14% in 2024-25. The New South Wales stations' time at MSOL increased to over 20% in 2023-24 before dropping back to 16% in 2024-25, still well above the levels seen in 2019-20 and 2020-21. For Queensland coal-fired plant, a noticeable increase from previous years was observed for 2023-24, and for 2024-25, where it was 13%. **Figure 8** shows the averages across New South Wales, Queensland and Victoria.

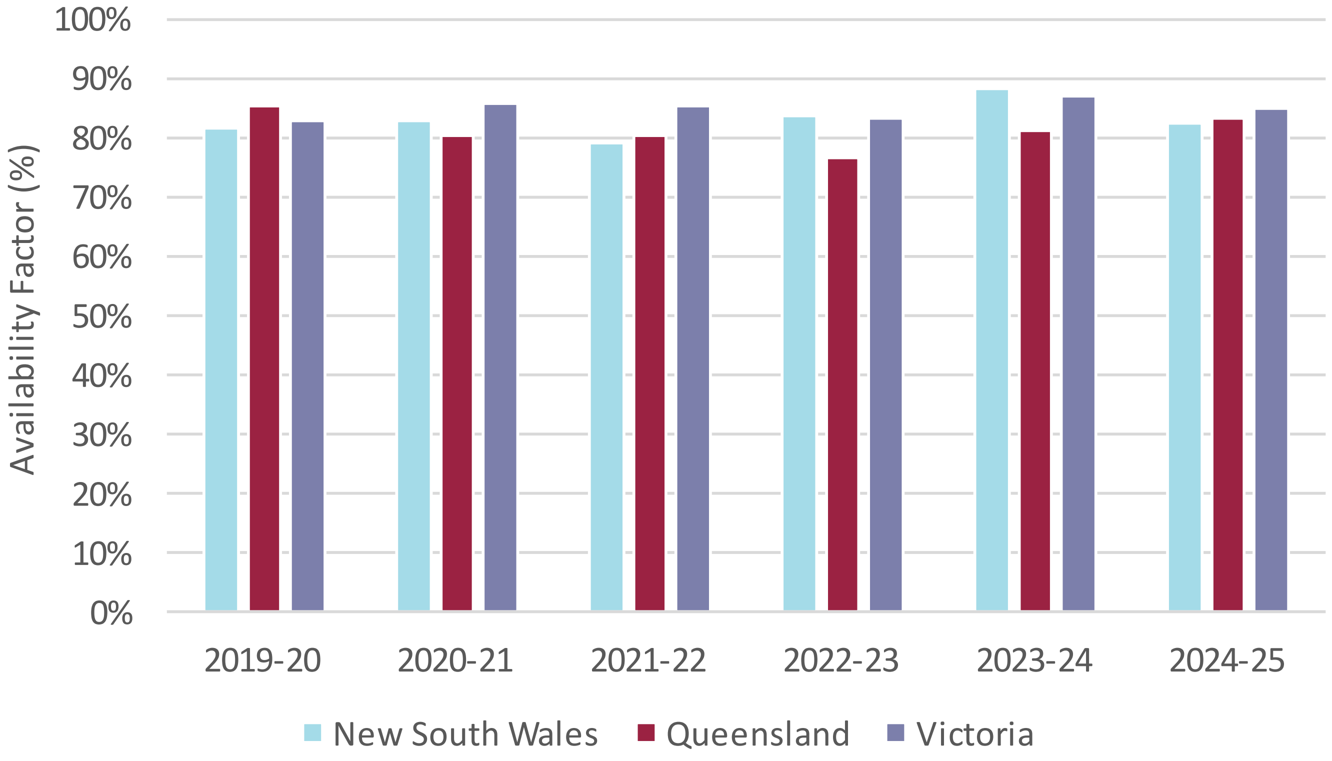
Figure 8 Combined coal fleet MSOL utilisation, New South Wales, Queensland and Victoria, 2019-20 to 2024-25



Coal-fired station availability factors

AEMO used the output over time data described above to determine the availability factors (defined in this case as percentage of time spent synchronised with the grid) of key coal-fired stations from 2020-21 to 2025-26, as shown in **Figure 9**. The data only includes the coal-fired plant, because this provides the great bulk of the generation, as discussed in Section 2; again, caution is required to extend this to be representative of a state or technology's overall performance. Note that a similar figure for gas turbine and other plant is not presented, because these plants are often off-line for commercial not technical reasons, which is generally not the case for coal-fired plant.

Figure 9 Combined coal fleet availability factor, New South Wales, Queensland and Victoria, 2019-20 to 2024-25



The analysis indicates that there is no significant change in the individual state and combined NEM coal fleet availability over the last six years. The reductions in availability in some years was mostly due to specific low probability but high impact events (for example, the Callide generator and cooling tower failures in 2021 and 2022 respectively[7]).

3.3 Flexibility characteristics

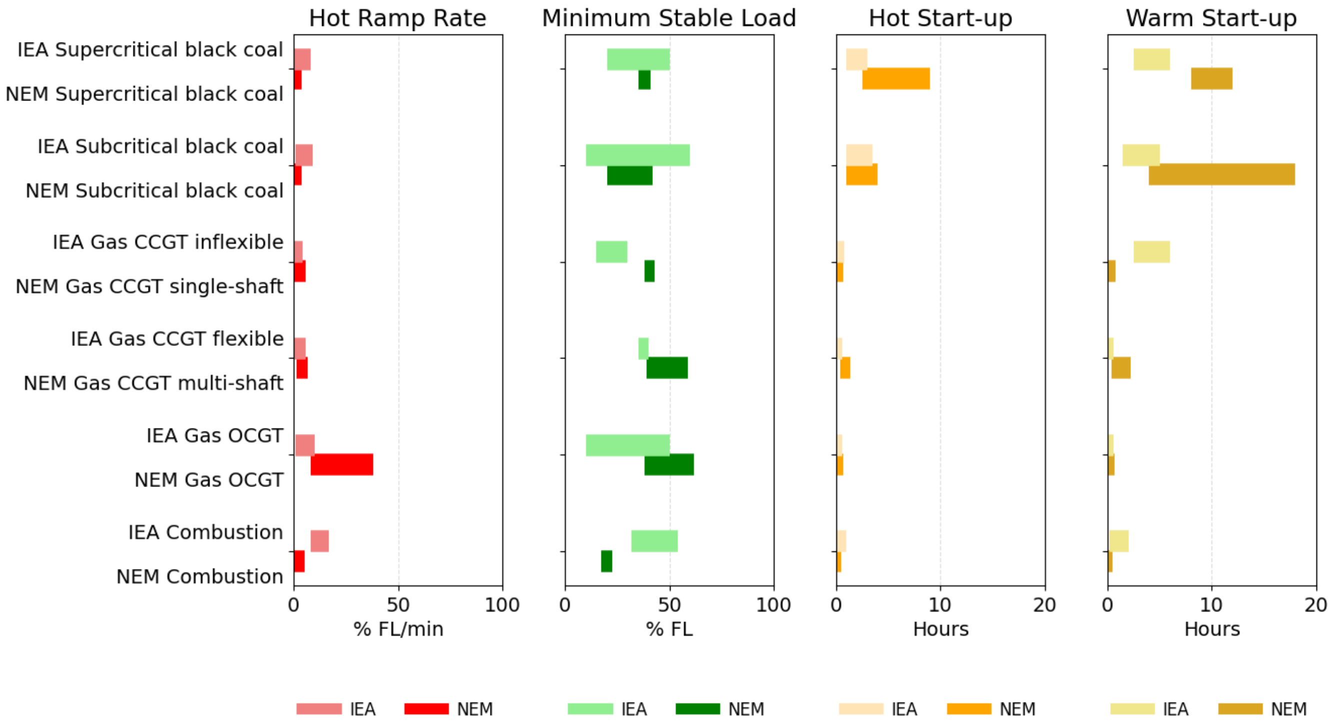
The flexibility of a power system relates to its ability to respond to variations in supply, demand and network conditions. It is underpinned both by power system infrastructure including generating plant and influenced by technical, regulatory and market factors. Global data has been collated by the International Energy Agency (IEA) in its *Status of Power System Transformation 2018* report[8].

Technical parameters of plants with different generation technologies are visualised below in **Figure 10**, illustrating how different technologies contribute to power system flexibility. These parameters vary significantly, not only between different technologies, but also for the same technology. For example, the minimum stable load for a station is coupled to the negative wholesale price around midday and the incidental cost in maintenance. Therefore, economic incentives can increase the flexibility. An example of a regulatory restriction on variability is the minimum load for gas turbines being limited based on emissions.

[7] See https://www.csenergy.com.au/what-we-do/thermal-generation/callide-power-station/c4recovery and https://www.csenergy.com.au/what-we-do/thermal-generation/callide-power-station/callide-c-cooling-tower-rebuild.

[8] See https://iea.blob.core.windows.net/assets/ede9f1f7-282e-4a9b-bc97-a8f07948b63c/Status_of_Power_System_Transformation_2018.pdf (page 57).

Figure 10 Flexibility assessment of generation technologies



Notes: Individual stations have been annotated where the range is extensive. Figure reproduced with modifications from IEA, *Status of Power System Transformation 2018*.

The following general observations can be drawn from this flexibility assessment.

3.4 Hot ramp rates

The hot ramp rates of the plant in the NEM range quite widely, but for coal plant the rates fall within the IEA ranges. However, the gas-fired plant (both combined cycle and open cycle stations) in the NEM ramp rates are generally similar to, or greater than, the IEA cohort's ranges.

3.5 Minimum stable operating level

MSOL values for the coal-fired plant were generally aligned with the IEA ranges. The minimum stable load (as a percentage of maximum load) for some coal-fired stations has reduced in the last few years. Partly this has been due to an increase in the maximum loads as the original steam turbines were retrofitted by more efficient turbines, with no change in the minimum output, which was typically designed to be 40% of the original maximum output. On other occasions it was due to modification to the operational regime.

The minimum stable loads for the gas-fired plants were similar to, or greater than, those of the IEA cohort. A key contributing factor for the higher minimum stable load for gas turbines is often the environmental limitations for stack emissions: in general, gas turbines are technically able to operate at lower loads, but the MSOL limit is a function of plant emission controls and emission limits.

3.6 Hot and warm start-up times

Coal plants in the NEM were found to have longer warm start-up times, on average, than the IEA cohort. This was considered to be a consequence of the operating regime which involved few startups and long periods of generation between outages, which meant that little investigation was made on means to reduce these times. For the sub-critical coal fleet one station was an outlier, but there appears to be potential for reduction in time across this fleet.

Hot start-up times for the sub-critical coal fleet were similar to the IEA cohort, but the super-critical fleet showed longer times. This is considered to be influenced by the steady operating regimes for these plants leading to little need to investigate faster starts.

Startup times for the gas-fired turbine plant is very similar to gas turbines around the globe, which are generally of the same design from each of the manufacturers.

4 Operational needs and risks

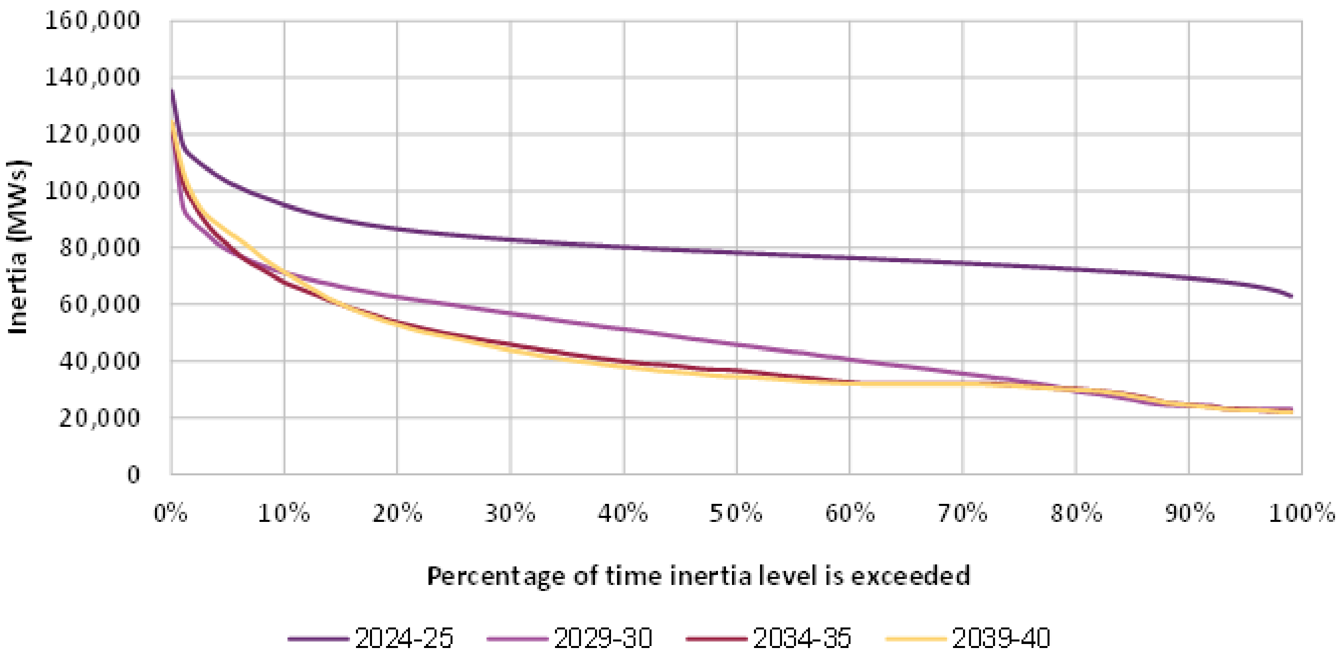
The key areas of this review to assess the operational needs and risks pertinent to the NEM from a network perspective were identified as system inertia, system strength, minimum operational loads, loss of reserves, ramp rate and system restart. Each is introduced and discussed in more detail in the sections below.

4.1 System inertia

System inertia is a critical component of power system security and operability and refers to the grid's ability to resist changes in frequency when there is a mismatch between generation and load. Such mismatches can occur due to generator trips or sudden changes in demand. A higher level of system inertia slows the rate of frequency change, allowing under- and over-frequency protection schemes to operate effectively.

Synchronous generators such as coal, hydro, and gas have historically provided the inertia necessary for system stability. However, as the energy transition progresses and thermal plants approach retirement, the overall inertia in the grid is declining. AEMO's 2024 ISP[9] illustrated the forecast decline in inertia due to generator retirements, if no new investment in inertia provision were to occur (see **Figure 11**).

Figure 11 Projected mainland NEM inertia, 2024-25 to 2039-40 (megawatt seconds [MWs])



Source: 2024 ISP, Appendix 7. System Security.

System strength service providers (SSSPs) in each region will be obligated to deliver system inertia within the same timeframes as system strength from December 2027[10]. In addition to synchronous sources of inertia such as synchronous

[9] 2024 *Integrated System Plan* for the National Electricity Market, Appendix 7. System Security, June 2024, at https://www.aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a7-system-security.pdf?la=en.

[10] See https://www.aemc.gov.au/sites/default/files/2024-03/ERC0290%20-%20ISF%20final%20determination.pdf (p. iv).

generators or synchronous condensers, grid-forming (GFM) battery energy storage systems (BESS) are emerging as a potential source of inertia[11].

4.2 System strength

System strength relates to the ability of the power system to maintain and control the voltage waveform at any given location in the power system, during both steady state operation and following a disturbance[12]. Like system inertia, it has been historically provided by coal-fired generation in the NEM.

As large volumes of variable renewable energy (VRE) have entered the NEM and older thermal plants have operated less frequently and retired, system strength has declined. In response, the AEMC introduced a rule in October 2021[13] to increase the supply of system strength by *implementing three broad components relating to the supply, demand and coordination of system strength. Together these should result in a more secure power system, easier and faster connections to the grid, and lower costs for consumers*.

AEMO's 2024 *System Strength Report*[14] projected system strength shortfalls across all NEM states except South Australia. These shortfalls are region-specific and depend on the operational status of synchronous generators within each zone.

4.3 Distributed photovoltaic impact on minimum system load

Minimum system load (MSL) refers to the lowest level of operational demand on the power system, typically occurring during the middle of the day when distributed photovoltaic (DPV) generation is at its peak. This condition challenges the ability of coal-fired power stations to reduce output sufficiently to remain online. While the coal generators are online, they provide essential system services such as system inertia and system strength as a byproduct of provision of energy. The issue is that the coal-fired power plants were originally designed to operate as baseload generators with their technical MSOL typically 40% of full capacity.

While most coal-fired plants have already reduced their MSOLs, the reduction may be insufficient to meet future minimum system load scenarios in the absence of further actions. These are described in Section 4.8.

AEMO's 2025 *General Power System Risk Review*[15] (GPSRR) identified MSL as a high-risk issue, particularly in relation to reduced inertia, insufficient system strength and system restart challenges.

AEMO's *Quarterly Energy Dynamics* (QED) Q1 2025[16] confirmed that DPV growth continued to offset operational demand. **Figure 12**, from the report, shows the relationship between DPV, operational demand, and underlying demand.

If operational security of the network is at risk, AEMO may have to intervene. There is potential for changes to coal-fired plant capability and operations to reduce the likelihood of this occurring.

[11] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf.

[12] See https://www.aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

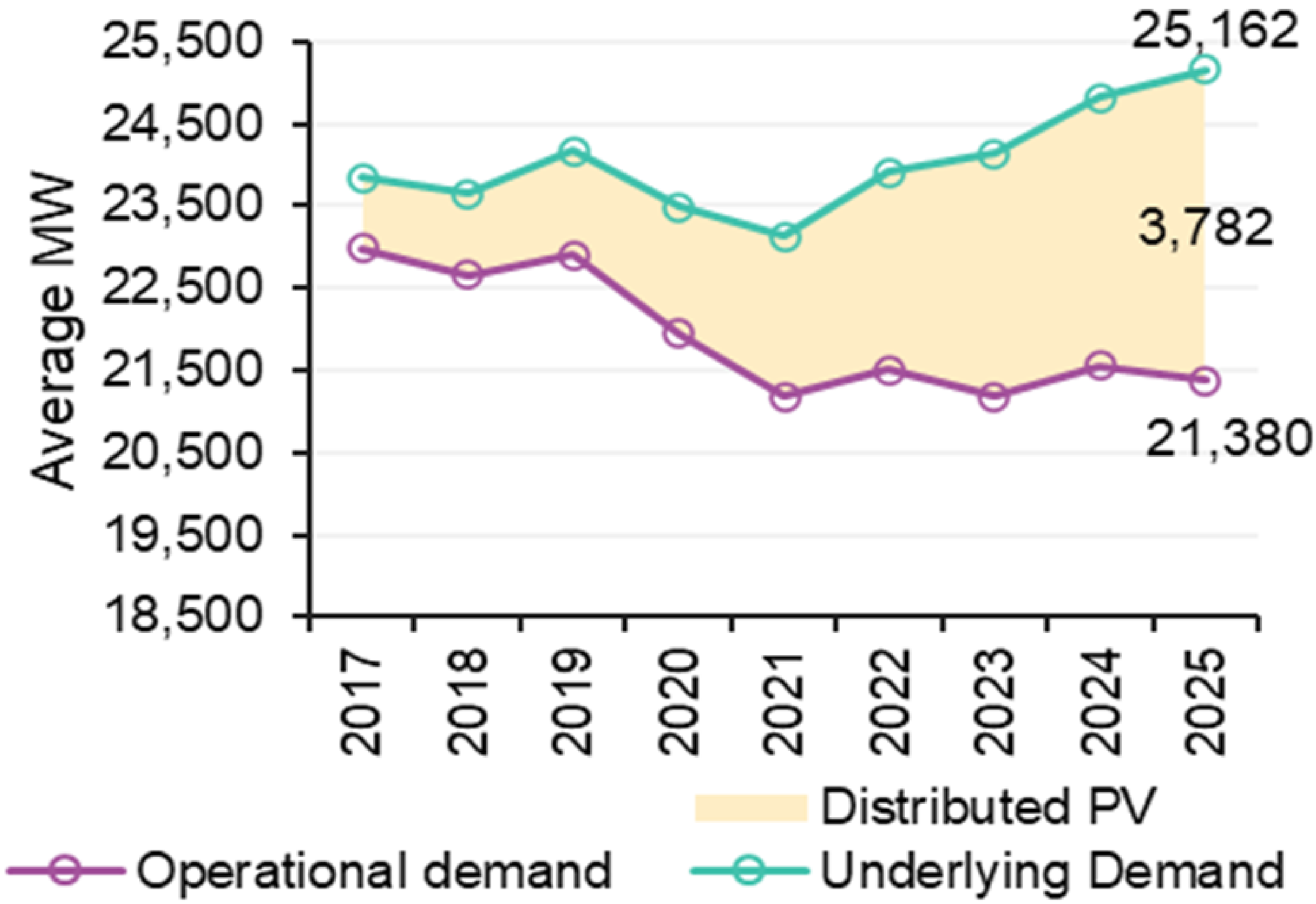
[13] See https://www.aemc.gov.au/sites/default/files/2021-10/ERC0300%20-%20Final%20determination_for%20publication.pdf (p. ii).

[14] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.pdf?la=en.

[15] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf?rev=dc6a972e71544bd3893299a4aaacf867&sc_lang=en.

[16] See https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q1-2025.pdf.

Figure 12 Distributed PV, operational demand and underlying demand, 2017 to 2025 (QED Q1 2025)



4.4 Capacity and reserves

AEMO defines three levels of lack of reserve (LOR) conditions when electricity reserves in the NEM fall below certain thresholds[17], and issues market notices to inform participants. An actual LOR occurs when the measures available, including market response to the forecast LOR, are inadequate to clear the LOR threshold.

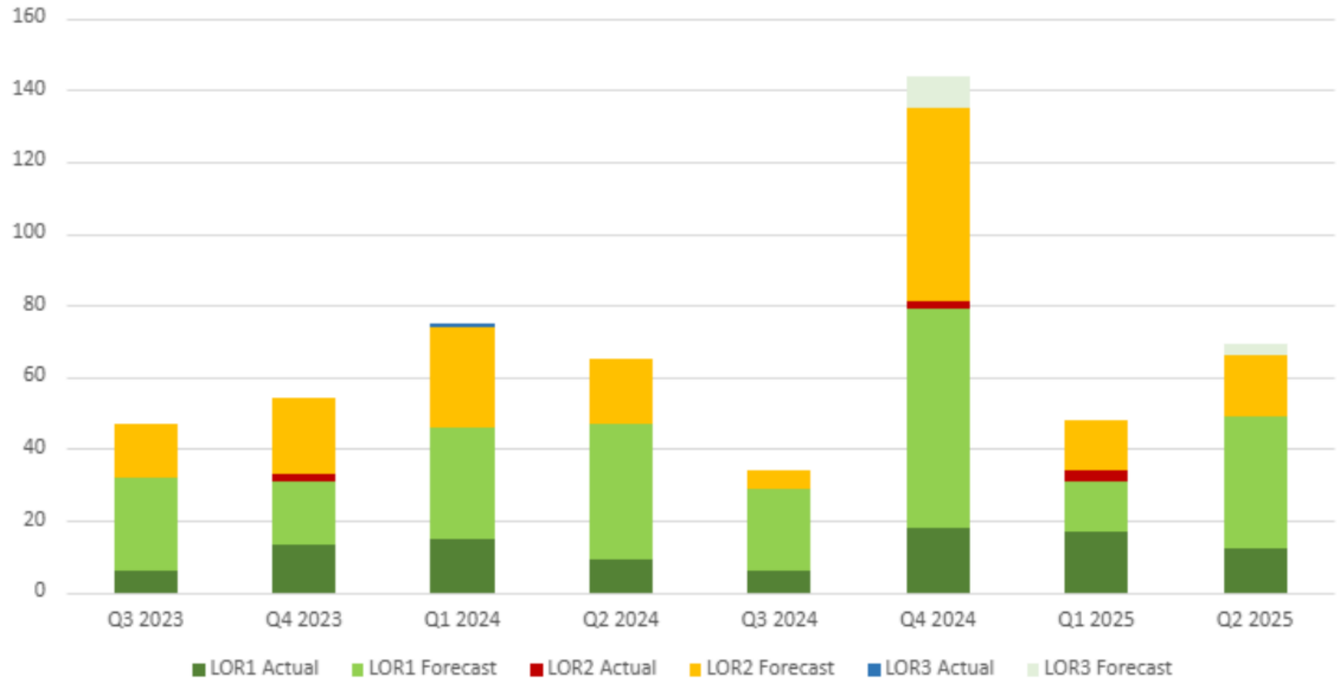
For example, **Figure 13**, extracted from AEMO's *NEM Lack of Reserve Framework Report* for 1 April 2025 to 30 June 2025[18], shows a relatively high number of forecast LOR conditions in Q4 2024, predominantly associated with New South Wales thermal plant outages in November 2024.

Increases in thermal generator maximum power capability may play a role in mitigating forecast or actual LOR conditions.

[17] See https://www.aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf.

[18] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/lack-of-reserve-framework-quarterly-reports/2024/nem-lack-of-reserve-framework-report---quarter-ending-31-december-2024.pdf?la=en.

Figure 13 NEM lack of reserve conditions Q1 2023 to Q2 2025



Note: from *NEM Lack of Reserve Framework Report* for quarter ending 30 June 2025.

4.5 Ramp rates

Variations in large-scale and DPV generation output in mornings and afternoons requires associated changes in other generation. Much of this change in load is currently covered by the thermal fleet (both coal-fired stations and the gas turbine fleet). As the DPV installed base increases, the role of the thermal fleet to vary its output will become more important, noting that the fleet was originally designed for steady high load operation and unit ramp rates were typically around 5 MW/minute. There is potential to increase these rates, but the impact on component life and maintenance needs to be considered. Over time as more BESS come online with charge and discharge capability, this may reduce the reliance on the thermal fleet.

4.6 Time to restart

For plant that is taken offline during periods of MSL, the notice periods require to deload and desynchronise, and for resynchronising, impact AEMO's ability to manage the system efficiently. These periods were often provided by the OEMs many years ago and are now being revisited by power station operators. This is an ongoing process to develop the necessary capability and manage risks that the plant is unable to re-start in the desired timeframe (with subsequent potential reliability impacts).

Typically, a two-hour notice period is required for both events, but these are expected to become shorter. After multiple two-shifts over several years, Ratcliffe on Soar 4 x 500 MW plant in the United Kingdom was reported to require 84 minutes notice for a restart.

4.7 System restart

System restart ancillary services (SRAS) providers capable of providing black start services are crucial to restoring the power system in the event of a blackout. These services are provided based on regional electrical sub-networks with the aim of restoring sufficient supply to the power system to allow other generating units to restart and allow restoration of the power system within a specified restoration time.

In the rare event of a system-wide network blackout or blackout of a sub-network confined to a region, sufficient and reliable SRAS is required to restore generation and transmission capacity within each of the regional electrical sub-networks.

Currently, AEMO procures SRAS services (including black start services) from interested parties who can provide these services for each of the regional electrical sub-networks as defined in the AEMO SRAS Guidelines[19]. To a large extent, black start services are currently provided by thermal generation capable of starting without any external supply or island forming facilities with trip to house load (TTHL) capability that can remain in operation after disconnection from the power system. These black start services are crucial to restoring sufficient supply to allow other generating units to restart and allow restoration of the power system after a blackout.

As thermal generation is retired from service, alternative replacements for the existing black start capable thermal generation will be required to maintain capability to restore the power system.

4.8 The evolving role of thermal power plant

Potential new modes of operation at times of MSL

The operational needs review identified two distinct requirements for the coal-fired fleet to be able to operate in a different way to the traditional practice:

- operation at a lower load without reducing the contribution to system inertia and strength, and
- short-term disconnection of some units from the grid to restore a margin between MSL and the remaining plant minimum output.

These two scenarios can be implemented in various ways.

For the coal fleet, the minimum output is influenced by several factors:

- the minimum number of mills required to remain in service to avoid boiler trips (typically three to four mill operation) – in some cases, modification to the auxiliary firing systems may be a partial solution, which will require combustion of more expensive fuel (gas, oil or briquettes),
- temperature and erosion constraints on boilers and turbines, and
- boiler chemistry and operational safety margins.

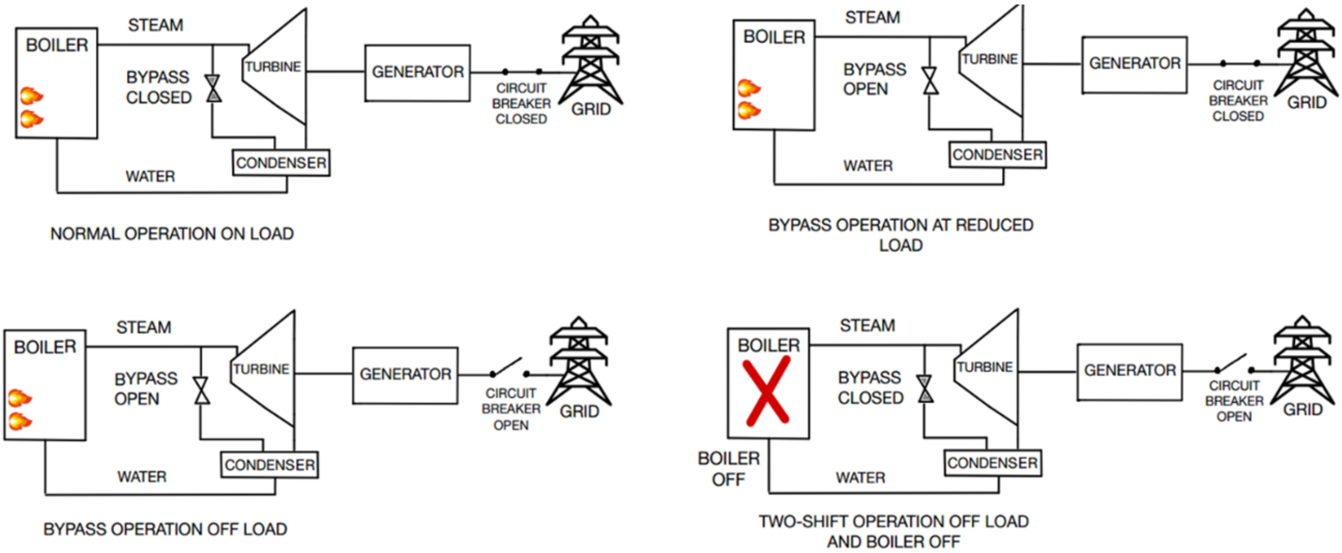
[19] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/sras/sras-guideline-2021.pdf?la=en.

Without engineering assessment and requisite hardware modifications/upgrades, operation at a reduced MSOL can present operational issues, stress plant components, reduce long-term reliability, and shorten equipment lifespan. This presents a potential flow on risk to system operability.

The present operating regime for coal plant involves operation at a negative system price during periods of low system load. There is therefore a commercial case for the output to be reduced further. Recent changes (collated through this review from the generator information sheets) show reductions in MSOL have been implemented at several stations. While further reductions are expected, the ‘easy wins’ have generally been implemented. Some owners may wish to shut down units during these negative price periods or to reduce output further by bypassing the steam turbine.

In principle, there are different ways of achieving this reduction in minimum output. **Figure 14** shows a schematic arrangement, where the top left diagram indicates normal operation (which may be reduced to a limited extent by operational changes), and the top right shows operation at a significantly reduced electrical output via steam bypass of the steam turbine, which remains synchronised. In this mode, the MSOL constraint is set by the turbine rather than the boiler. The two lower diagrams both show the turbine desynchronised from the network. The right hand diagram also shows the boiler shut down, a mode typically called ‘two-shifting’ from common usage primarily at coal-fired plants in Europe (and elsewhere), where it predominantly has occurred during the night shift when load was at a minimum.

Figure 14 Potential operational modes of coal-fired plant



Potential repurposing of generators for system strength and inertia

The potential conflict between owners’ desire to reduce costs during periods of MSL by two-shifting and the need to keep sufficient generators on-line to meet system needs can be offset by increasing the sycon contribution to the network. SSSPs are tasked with implementing this, with AEMO directions used as a last resort. In addition to procurement of new system strength solutions, including greenfield syncons, a potential source of sycon capacity is through the repurposing of existing coal-fired plant generators and by conversion of gas turbine generators (and, for CCGTs, the associated steam turbine generators) to solely syncon duty or dual use. A 2023 DIgSILENT report commissioned by the Australian Renewable Energy Agency (ARENA)[20] showed that it is feasible to repurpose or convert these generators.

For gas turbine plant, a clutch could be added to the drive train so the generator could either be operated in synchronous condenser mode by engaging the clutch, or the gas turbine could operate as normal. For steam turbine generators on plant that has been (or will shortly be) retired, the generators could be repurposed to a syncon but without the option for reversion to normal operation. (In Europe this typically has been implemented for the steam turbine generators on gas turbine plants that have been converted from multi-shaft CCGTs to OCGTs). The third option of repurposing gas turbine generators as solely syncons conflicts with the need for these generators to produce power at times of high system load.

The DIgSILENT 2023 report considered various refinements to this basic concept, including de-blading steam turbines and adding flywheels to increase the inertia. It concluded that, at face value, syncon conversion should provide a cost-effective way of providing the required security services to the power system if it could be provided through an existing point of connection (PoC), which already has most of the required infrastructure to support the operation of the plant as a syncon. The size of the larger generator units (upwards of 750 megavolt amperes [MVA]) is several times that of a standard syncon (around 125 MVA to 250 MVA), meaning one conversion could substitute for up to three or more new syncons. Hydro generators can, and are, also used for this purpose, with many already able to operate as syncons. Comparatively, the inertia gain for fossil-fuelled generator repurposing is much greater than that available from hydro.

The approach depends on the technology surrounding the generator:

- Hydro generators are generally the easiest to convert and many existing hydro generators already have the capability to operate as syncons. Conversion is relatively simple and involves de-watering the turbine. An advantage of this process is that the full inertia is retained.
- Gas turbines are typically located on ground-mounted foundations – extension of foundations is easier than for steam turbines. When operating as a syncon, the turbine is disconnected, and the inertia is reduced.
- Steam turbine generators can be converted by disconnecting the turbine (reducing the inertia to about one-third of the steam turbine generator value), de-blading the turbine, or fitting a flywheel, which increases the level of difficulty. Shaft modifications are required, and this can be challenging on the elevated foundations. Cooling arrangements may also present challenges. The steam turbine generator will require a mechanism to run it up to synchronous speed, which can either be a motor or frequency converter.

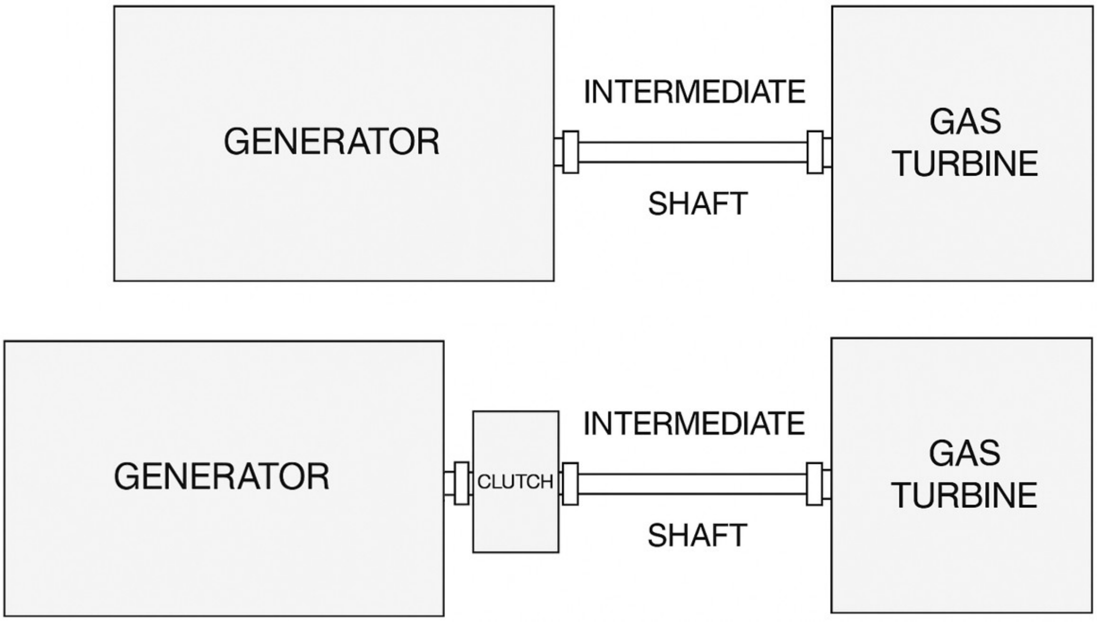
In addition to repurposing generators at the end of their operational life, there is the potential option of utilising spare generators which are stored by some power plants. A feasibility study, funded by ARENA for Loy Yang B[21], is looking at provision of essential system services using the spare generator and suitable location for a syncon. Depending on the detailed configuration, this could provide a syncon with capacity equivalent to repurposing an operational generator.

For the larger gas turbines, dual use as a syncon or as normal operation may need the spacing of hardware to be increased to accommodate the clutch, as shown in **Figure 15**.

[20] DigSILENT, June 2023, *Repurposing existing generators as synchronous condensers,* Report on technical requirements, at https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

[21] *Alinta – Loy Yang B 'Stage 1' Synchronous Condenser Project*, at https://arena.gov.au/projects/alinta-loy-yang-b-stage-1-synchronous-condenser-project/.

Figure 15 Addition of clutch between generator and large gas turbine to allow syncon operation



A clutch is not required for syncon operation of the smaller aero-derivative gas turbines, but the consequent syncon inertia per conversion is significantly less than either a new syncon or a repurposed or dual use generator from a coal-fired plant, or a large gas turbine. Further consideration of the gas turbine options and their limitations has been provided by the two main OEMs for the Australian gas turbine fleet, Siemens Energy and GE Vernova, in Section 8.

Provision of higher maximum generation at times of low reserves

It is considered that there is some potential for higher maximum loads for short periods if there is room within the existing agreed (or modified) Generator Performance Standard (GPS). Typically, this involves increasing the boiler fuel input and reducing the steam flows to the boiler feedwater heaters. More steam then goes through the turbine, giving more output but at a reduced efficiency. This will be a commercial decision by the owners.

Ramp rate increase

Engineering assessment may lead to relaxation of the constraints limiting ramp rates, but the limiting factor would often be the time required to bring additional coal pulverising mills into service.

Reduction in notice time to restart

This can be progressed by stations as part of the trials to bring two-shifting into a mainstream mode of operation.

Additional stations to offer SRAS services

This can be managed by AEMO through its SRAS tendering process. The adequacy of the existing system restart services and procedures is outside the scope of this report.

5 Timeline, costs and risks for implementation of new operational modes

The anticipated timelines for each of the thermal fleet flexibility enhancements have been assessed at a high level.

Table 1 Timeframes, costs and risks of potential opportunities

Potential opportunity	Project timeframe	Delivery and commercial risk	Indicative cost estimate per unit (AUD $M)
Reduce MSOL by reducing number of in- service mills with supplementary firing for boiler stability	One or two years to reengineer supplementary fuel system, implement at major outage.	High as stability change is not a given, also cost of supplementary fuel is a commercial risk.	10
Steam bypass to condenser so effectively near zero (or low) load, but synchronised	Less than a year, longer if for example steam bypass system needs modifications. If so, implement in a scheduled outage. If there is no steam bypass system, design etc will take longer again (and may not be feasible).	Medium, impact on steam turbine blading and steam bypass system needs to be assessed.	1 - 20, 80 - 100 if new system is required
Addition of clutch to allow syncon mode, most likely on gas turbine unit	See Table 2 below.	High commercial risk as potential timing impact for switch of modes.	25 - 45
Generator permanent (end of life) conversion to syncon	Nine months assuming engineering design and equipment procurement occurs prior to end of life	High as working around plant that may be in demolition.	20 - 120 depending on option
Spare generators or parts to be repurposed at new location	See Table 2 below. PoC works to be implemented in parallel. If end of life generator is used engineering and site preparation can be done before end of life: then nine months to implement and commission.	High as using used equipment, also connection risk as the syncon will be additional plant and outside the current connection arrangements.	160 (ARENA report will determine more accurate estimate)
Conversion of aeroderivative gas turbine (GT) generator to dual use	Expected to be up to six months for control and related modification to be designed, implemented and commissioned. Some of these tasks can be done prior to shutdown of the GT.	Moderate risk on first of a kind, then low risk.	1 - 5
Increase maximum load and ramp rate, reduce hot restart time	Need engineering assessment, then primarily operational changes with plant online. Engineering and trials to take up to a year.	Engineering assessment is low cost and risk. Application of outcomes will vary in operational and asset life risk depending on the site and extent of change.	<1M for engineering assessment

For enhancements that require significant engineering work, such as conversion to syncon, the timescales could potentially vary widely[22], as **Table 2** shows. AEMO assumed typical estimated timelines for engineering studies, and current estimates of procurement times for new equipment and time for approval to proceed and for installation and commissioning. The elapsed time is primarily contingent on the time to reach a financial investment decision, the delivery of long lead time items, and whether these are procured partway through the detailed design phase, noting the risk that the project does not proceed, and cancellation fees will be applied.

[22] These timescales are indicative: feasibility studies will give more accurate estimates on a case-by-case basis.

For gas turbine conversion to syncon the timescale could be as short as 28 months, with the site work taking the final nine months, during which time the gas turbine is out of operation or in commissioning.

For end-of-life conversion of a steam turbine, the overall timescale is likely to be longer as there are more long lead items to procure (for example, a pony motor), but with forward planning, the syncon could be operational in as little as seven months from the end-of-life date if foundation modifications are not required. This would require engineering studies to commence around three to four years prior to end of life.

Table 2 Anticipated timelines for each of the thermal fleet flexibility enhancements

Task	Likely timeframe (months)	Elapsed time range (months)
Feasibility/options study	2 to 6	2 to 6
Select option	2	4 to 8
Detailed design and establish cost	2 to 8	6 to 16
Business case and investment decision	3	9 to 19
Procure hardware	12 to 24	19 to 43
Remove redundant hardware	1	20
Modify foundations (if required)	2	22
Install new hardware	3	25 to 46
Commission and handover	3	28 to 49
Hand over documentation	1	28 to 50

In parallel with these timelines, if the enhancement is to an operating plant, it is highly likely that implementation will be during (and potentially extending) a scheduled outage.

6 Selection of key stations for further analysis

6.1 Selection criteria

AEMO classified the key thermal power generation technologies described in Section 2 by their intrinsic attributes – technology type, fuel type, region, size, and turbine and boiler OEMs – then applied a secondary set of attributes – owner/operator, expected closure date, and SRAS capability. Importance was assigned to each attribute:

- region (particularly those in New South Wales and Victoria with forecast system security shortfalls[23]),
- size (larger units are better placed to provide system strength and security),
- turbine and boiler OEMs (covering most common range of technology types in the NEM),
- system restart (stations crucial for system restart services were given a higher priority), and
- owner/operator (seeking to cover a diverse range of operators, where possible, subject to other criteria).

After considering these factors, stations were assigned to a priority group from 1 to 3 for the purpose of this review. Group 1 stations were sent a questionnaire survey and accompanied by either an on-site or owner's office visit, while Group 2 stations were only sent a questionnaire with a follow-up Teams meeting if required. For Group 3 stations, no action was taken as part of the 2025 Thermal Audit.

In the case for Group 1 stations, other pertinent assets in the owner's fleet/portfolio were treated as Group 2.

Note: Priority grouping does not necessarily reflect a particular power station's importance within the NEM thermal fleet.

Black coal (sub-critical)

Table 3 Selection justification for sub-critical black coal generators

Generator	Selection	Justification
Bayswater	Group 1	Covers the 660 MW IHI and Toshiba combination. Recently trialled both steam bypass and boiler box-up two-shifting. Unit closure dates are 2033.
Eraring	Group 1 (site visit)	Origin Energy undertook some initial investigation of the potential to reuse the station as a syncon, after its imminent closure scheduled in 2027, but has not progressed this.
Tarong	Group 1	Local black start capability, standard Hitachi 350 MW boiler/turbine combination in common with Callide B and Stanwell Power Station.
Vales Point	Group 1 (site visit)	Covers the GE Power boiler as opposed to the IHI unit.
Callide B	Group 2	Similar equipment to Tarong Power Station (same OEM).
Mount Piper	Group 2	Design is similar to Bayswater (same OEM) and Mount Piper has two units compared to Bayswater's four.
Stanwell	Group 2	Same OEM as Tarong and Callide B.
Gladstone	Group 2	One off station that is scheduled for closure in 2035.

[23] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/aemo-2024-transition-plan-for-system-security.pdf.

Black coal (super-critical)

Table 4 Selection justification for super-critical black coal generators

Generator	Selection	Justification
Callide C	Group 2	Similar priority to the other super-critical plants.
Kogan Creek	Group 2	Covers Mitsubishi Power and Siemens Energy combination.
Millmerran	Group 2	Covers B&W and Ansaldo combination.
Tarong North	Group 2	Earliest scheduled shutdown (2037) and is a smaller station than the others but will be reviewed alongside review of Tarong.

Brown coal

Table 5 Selection justification for brown coal generators

Generator	Selection	Justification
Loy Yang A	Group 1 (site visit)	Has one Brown-Boveri turbine and three KWU units. Newport uses the same BB turbine and generator (potential synergies).
Loy Yang B	Group 1 (site visit)	High flexibility, recent improvements made with investigations ongoing. Open discussion with Alinta.
Yallourn	Group 1 (site visit)	Imminent closure may give opportunity for conversion to syncon. Also, opens discussion with EnergyAustralia.

Gas turbines

Table 6 Selection justification for gas turbine generators

Generator	Selection	Justification
Colongra	Group 1 (site visit)	Chosen to cover GT13E2 due to its proximity to load centres in New South Wales and opens discussion with Snowy Hydro.
Jeeralang A/B	Group 2	Capability for black start and provision of SRAS.
Tallawarra A/B	Group 2	Proximity to load centres in New South Wales and high efficiency upgrade (large single shaft CCGT).
Laverton North	Group 2	Covers SGT5-2000E and is close to load centres in Victoria but considered lower priority than Colongra.
Mortlake	Group 2	Close proximity to load centres in Victoria and Origin Energy ownership also syncon studies have been undertaken (but not progressed).
Pelican Point	Group 2	Colongra (similar 13E2 technology) chosen in preference.
Hunter Power Station	Group 2	Part of Snowy Hydro's fleet in New South Wales and covers Mitsubishi type F.
Osborne	Group 2	Was a Combined Heat and Power (CHP) plant, now operating as CCGT. Could be converted to OCGT as well as CCGT operation
Darling Downs	Group 3	Location is remote from New South Wales so less interest in system security and inertia.
Townsville Power Station	Group 3	Laverton North chosen in preference, despite addition of clutch in Townsville to enable a syncon role. Also remote location.

Reciprocating engines and others

Table 7 Selection justification for reciprocating engines and other generators

Generator	Selection	Justification
Newport	Group 2	Same steam turbine as Loy Yang A unit 2, in EnergyAustralia portfolio.
Barker Inlet	Group 3	Not identified as pertinent.
Torrens Island B	Group 3	Scheduled for closure in 2026 and South Australia of comparatively less interest.
Moranbah North	Group 3	Not identified as pertinent.

Summary

The final selection of plants is as follows.

Eight Group 1 stations:

- three brown coal-fired plants,
- four sub-critical black coal-fired plants, and
- one gas turbine plant.

Sixteen Group 2 stations:

- four black coal sub-critical plants,
- four black coal super-critical plants,
- seven gas turbine plants, and
- one gas-fired sub-critical boiler plant.

6.2 Information gathering

A questionnaire was developed to cover the key areas identified in the desktop studies, and sent it to the owners of the Group 1 and Group 2 stations, requesting responses on a voluntary, confidential basis. The information was requested in two parts. Only de-identified aggregated information and non-confidential information is included in this report. Consent has been obtained from participants for the disclosure of information.

Questionnaire Part A:

- **general** including data confirmation, asset management planning and operational targets, and
- **operations management** including potential changes to performance expectations, fuel supply security, impact of environmental permit levels, black start and system restart ancillary services.

Questionnaire Part B:

- **operational changes** including technical factors that constrain the current maximum and minimum generation, start times and loading ramp rate values, trials undertaken and planned, including two-shifting and steam bypass operation, and black start potential enhancements,

- **potential major plant modifications** including syncon repurposing at end of life, dual mode operation (normal generation and syncon mode) and use of spares to create new syncon(s), and
- **specific information** including around notice times required for potential short-term shutdowns/two-shifting and restart.

Site visits

AEMO and its consultants AEP Elical visited Group 1 stations, except for Bayswater where the staff joined in a Teams call, and Tarong where the meeting was held at the Stanwell head office in Brisbane.

7 Survey findings

7.1 New South Wales black coal plants

The New South Wales black coal stations generally consist of 660 MW sub-critical coal-fired boilers of similar design with IHI boilers and Toshiba turbine generators.

All the stations have asset management plans that they consider adequate to maintain the present level of unit availability, but some identified that the outage scope could be reduced if closure of a unit was anticipated before the next major outage.

With the exception of Mount Piper, the stations considered that coal was available up to the planned closure dates. Mount Piper is presently investigating alternative sources of coal supply after the expected closure of the Springvale mine as well as options for mine de-watering to prevent mine flooding and allow for more flexible operation of the station. Also, the present supply requires a sufficient level of generation to produce fly ash that is needed to stabilise the mine drainage water. Some sites discussed that, despite mine leases containing coal for longer term operations, concern around mine life extension approval risk (and delays to those) exist, which affects commercial life and investment decisions of coal fired stations.

All stations surveyed have considered reducing their MSOL and have conducted trials to identify how far minimum load operation could be reduced within the constraints of the station.

Further reductions depend on mitigating constraints, generally around boiler stability – three mill operation would reduce the risk of boiler trip by allowing an additional mill to be started should one trip. There have also been various high-level studies to see how enhanced start-up fuel provision could allow two mill operation with a reduced boiler output. However, these have not been progressed, due at least in part to

- a limited reduction in boiler output,
- the need in some cases to upgrade the start-up fuel infrastructure, and
- the high cost of the start-up fuel, which was generally diesel fuel.

There was also a potential constraint on the minimum turbine output, particularly for those units where no turbine upgrade had been implemented. The main factor was the risk of last stage low pressure blade damage leading to the need for comparatively frequent inspections and potentially turbine replacement.

Several stations have investigated using a turbine bypass system to direct steam to the condenser thereby reducing steam flow through the turbine to the minimum level that was considered viable. In some cases, stations identified that this would also require upgrading the steam bypass system and potentially reinforcing the condenser to stop damage to the first rows of tubing. Vales Point does not have a turbine bypass system and is unable to operate in this way.

None of the New South Wales stations have TTHL capability, but trials have been undertaken at some plants to reduce the turbine steam flow to zero and desynchronise the turbine. Typically, two hours' notice is required to do this, and two hours' notice to resynchronise. During this period the boiler will continue to operate with the steam going direct to the condenser. Thus, coal combustion and carbon emissions will continue despite there being no generation. While the trials have been successful, the stations considered further trials and revisions to operating manuals and procedures are necessary before this can become a regular option and these may lead to identification of required engineering modifications, on a plant-by-plant basis. The consensus view is that this will take approximately one year.

Some stations have also trialled the option of shutting down both the turbine and the boiler during the solar peak (typically called two-shifting). Similar notice periods will apply and, for the plants where this has been trialled, further work taking about a year is expected. AGL Bayswater has commented publicly on its two-shifting trials[24]. Initially trials involved steam bypass to the condenser, but two-shifting with the boiler shutdown has also been trialled successfully. Other stations have reservations about the feasibility of this mode of operation; the main concerns are enhanced plant degradation and the risk of not returning to service on schedule and not getting income, both leading to significant increase in costs.

7.2 Queensland black coal plants

The Queensland black coal sub-critical stations generally consist of 350 MW units of similar design with Babcock Hitachi boilers and Hitachi turbine generators. The newer stations in Queensland are of the black coal super-critical design with some differences in plant design and equipment used.

Respondents noted that their stations have asset management plans that they consider adequate to maintain the present level of unit availability.

The owners that responded considered that coal was available up to the planned closure dates.

Owners' responses stated that their stations have considered reducing their MSOL load and have conducted or are planning to conduct trials to identify how far minimum load operation could be reduced within the constraints of the station. Further reductions depend on mitigating constraints, generally around boiler combustion stability. Three mill operation was considered necessary to allow an additional mill to be started should one trip, without having a boiler trip. Using start-up fuel at low loads was considered in the responses to be too costly due to high cost of the start-up fuel, which generally is fuel oil.

There also is a potential constraint on the minimum turbine output due to the risk of last stage low pressure blade damage, maintaining minimum steam flow and controlling back-end temperatures, which could lead to potential damage requiring comparatively frequent inspections and potential turbine blade replacements.

While two-shifting is likely to be technically feasible at some stations, the stations have not and are not planning to investigate two-shifting. The impact to cost and plant life is seen as significant due to accelerated life consumption throughout the plant.

Some of the stations have TTHL capability and can be used to provide SRAS, but this mode of operation is limited in duration and number of TTHL events per year due to long-term effects on the plant.

[24] Bayswater LinkedIn post, September 2024, two-shift/bypass operation.

7.3 Victoria brown coal plants

The availability was highest for Loy Yang B (LYB). LYB, which has a long planned operational life, has undertaken more investigation into operational enhancements, as has Loy Yang A (LYA).

Both LYA and LYB receive coal from the Loy Yang open pit mine, which has sufficient reserves for the planned station operational lives and there are no identified constraints on other key inputs (such as water and start-up fuel).

While the stations have investigated and implemented lower MSOLs, the extension to low load or zero operation through steam bypass or two-shifting has not been investigated. At least in part this is due to concerns regarding combustion stability of the brown coal. Turbine and Turbine Bypass System integrity is also a concern that requires further assessment.

7.4 Combined cycle gas turbine and large open cycle gas turbine plants

The responses to the questionnaires showed a wide range in capability to burn gas and diesel, with different environmental limits and duration constraints. Some were gas only with gas available for baseload operation, others could have a four hours per day constraint on gas supply, while another could burn diesel but needed gas for start-up and shutdown. There were few planned major modifications noted in the responses.

The minimum load at most of the stations is limited due to environmental constraints on emissions. Most OEMs can provide gas turbine upgrades which would enable MSOL operation down to 10% of capacity while still meeting the required emissions levels. Only a few stations have implemented upgrades during major overhauls due to the significant cost associated with these upgrades.

Similarly, OEMs also offer upgrades to increase the output from their gas turbines, but this has generally not been considered due to the high cost being uneconomical for stations that operate as peaking plant with limited operation.

For the OCGTs, conversion to a standalone syncon only is comparatively straightforward, but is not being considered by any of the stations. Conversion to dual use, which requires a clutch between the generator and the turbine, is more complex and may lead to operational constraints (for example, when changing from syncon to generation mode), and currently no conversions to syncon are being planned. Although they were not identified as group 2 stations in this review, AEMO understands that Snuggery is syncon capable, and Townsville (a CCGT that can also operate as OCGT) has recently converted the gas turbine to provide a dual use syncon/generation (capable of normal generation and syncon operation)[25].

7.5 Open cycle gas turbines – small

The small OCGTs were mostly classified into group 3; only Jeeralang was classified as a group 2 station for the purpose of the review and sent questionnaires. Therefore, information is primarily derived from operational data and information from the OEMs.

While their present role is to generate when the system clearing price is high, there is potential to implement syncon duty on the aeroderivative gas turbines with minimal modifications (for example, GE LM2500 and LM6000). The conversion eliminates the need for a clutch and mainly requires control system upgrades without major hardware changes. This would

[25] See https://www.siemens-energy.com/global/en/home/stories/Townsville-grid-stability.html.

allow dual use – noting that when the units were bidding to provide generation there would be little need for additional inertia, so allowing a straightforward change of use. While the individual units will not provide much inertia across the fleet there is potential for a reasonable contribution. More detail on the work involved is in the discussion of the GE Vernova response, in Section 8.2.

7.6 Other technologies including thermal gas, reciprocating engines and biomass

The remaining generation plant – comprising thermal gas, reciprocating engines, biomass and landfill gas – were mostly classified into Group 3, so no questionnaires were issued, and information was primarily derived from operational data.

This shows that the impact on system stability is small, particularly as the plants are either on-line only sporadically or are non-scheduled generation (for example, the biomass and landfill gas stations). The plants' capacities are also small (excepting the multiple reciprocating engines at Barker Inlet), so any impact is reduced accordingly.

Newport, a 500 MW gas-fired Rankine cycle plant, was categorised as Group 2. It has a low capacity factor, being operated mainly on warm standby, therefore its main impact on the Victoria network is to provide power when demand is high. It is capable of two-shift operation, but this has not often taken place. The other gas-fired thermal plant, Torrens Island B in South Australia, is scheduled for imminent closure and has not been reviewed.

8 OEM engagement

Complementary questionnaires were developed and sent to the key OEMs, with responses summarised below.

8.1 Siemens Energy

Siemens Energy provided verbal responses to the questionnaire and followed up with some examples of post-closure syncons (Killingholme[26] and German nuclear powered steam turbine generators[27]).

The main insights were provided on enhancing the flexibility of existing gas turbine stations, syncons (new and conversions) and on new gas turbine plant. There was limited discussion on enhancing flexibility of the coal-fired plant. **Table 8** below is a summary of the larger Siemens Energy gas turbine models generally installed in the NEM.

Table 8 Summary of larger Siemens Energy gas turbine models generally installed in the NEM

GE Model	Type	Use	Typical rating (MW)	Number installed
SGT-600	Industrial	OCGT	24	2
SGT-800	Industrial	CCGT	50	2
V93.0	Industrial	OCGT	50	2
V93.1	Industrial	OCGT	60	4
SGT5-2000E	Industrial E class	OCGT/CCGT	170	12
SGT5-4000F	Industrial F class	OCGT	300	2
SGT-A65	Aero	OCGT	60	1

Siemens Energy has various upgrade options to enhance the flexibility of existing gas turbines/CCGTs, and has a live project overseas that is planned to demonstrate the improvements that can be achieved. No further details were supplied for this project, but more generally capital expenditure may be required for significant improvements.

Siemens Energy is the supplier for the dual use syncon conversion at Townsville which will allow the plant to operate as a sycon or as a normal generator by installing a clutch. In this case there was no need to move the generator, so the conversion was straightforward. No flywheel was installed. The switchover time from disconnect of the syncon to resynchronising as a normal gas turbine generator or vice versa was stated to be approximately 25 minutes.

Siemens Energy considered conversion of its large E & F class gas turbine generators is feasible. It has designed a clutch for new F class machines (nameplate rating 385 MW) and has bid syncon conversion for F class projects. The conversion engineering depends on the plant configuration so needs to be investigated on a site-by-site basis.

Siemens Energy said that adding dual use as a syncon to a new build gas peaking plant is relatively simple and would only increase the equipment supply cost by ~5%.

[26] See https://urldefense.com/v3/__https:/www.siemens-energy.com/global/en/home/stories/killingholme-rotating-grid-stabilizer-conversion.html__;!!HKeyBm8!T8Ir8S6z9k_j67BNTu1_bjOaEQU4h_l9z-VAMXcOg_zPfPx1ggUMAgh2iUMS7lj-YfknIi_B9fR7rAIfNy7KhDpABgn8KyzhbUM$.

[27] See https://urldefense.com/v3/__https:/studylib.net/doc/10491399/biblis-a-generator-stabilizes-the-grid-as-a-synchronous-c...__;!!HKeyBm8!T8Ir8S6z9k_j67BNTu1_bjOaEQU4h_l9z-VAMXcOg_zPfPx1ggUMAgh2iUMS7lj-YfknIi_B9fR7rAIfNy7KhDpABgn85tJ-FHA$.

Despite the German syncon reference, Siemens Energy has experienced issues regarding the practicality and economics of repurposing of retired plant, particularly if the rest of the facility was to be demolished (this was not the case in its two reference projects). It also commented that it may prove difficult to get insurance on converted syncons, as they may be considered a 'change of use'. In the end, it may prove more economical to build new syncon units nearby that can take advantage of the existing grid connections from the decommissioned plant. Siemens Energy also noted that converting the existing steam turbine generator to a syncon would be more complex as a pony motor would be required to bring the generator up to speed to match system frequency.

Siemens Energy noted the typical practice is to design new CCGT plants for maximum efficiency for baseload operation. If flexibility (for example, short start times) was a key criterion, it may be worth considering reducing some operating parameters (such as steam pressure) to simplify the steam system design. While this would reduce peak efficiency, the overall fuel consumption may be reduced if it allowed faster start times. It noted that in the Australian market there might be few engineering, procurement and construction contractors for new build combined cycle plants that would be willing to offer the required guarantees.

Siemens Energy offers, and has been successful in winning tenders for, new syncons. It is increasing its production capability for these with an aim to reduce lead times.

8.2 GE Vernova

GE Vernova (GEV) provided a written response to the questionnaire. The current installed gas turbine fleet in the NEM comprises a number of GEV units consisting of both aeroderivative and industrial frame type machines. **Table 9** below is a summary of the GEV larger gas turbine models generally installed in the NEM.

Table 9 Summary of larger GEV gas turbine models generally installed in the NEM

GE Model	Type	Use	Typical rating (MW)	Number installed
LM2500	Aeroderivative	CCGT, heat recovery	30	3
TM2500	Aeroderivative	OCGT	30	9
LM6000	Aeroderivative	OCGT	40	4
Frame 5	Industrial	OCGT	17	12
Frame 6B	Industrial	OCGT	40	6
MS-9001	Industrial	OCGT	70	3
Frame 9E	Industrial E class	OCGT/CCGT	120	6
Frame 9F	Industrial F class	OCGT	320	1
GT13E2	Industrial E class	OCGT/CCGT	180	10
GT26	Industrial F class	CCGT	240	2

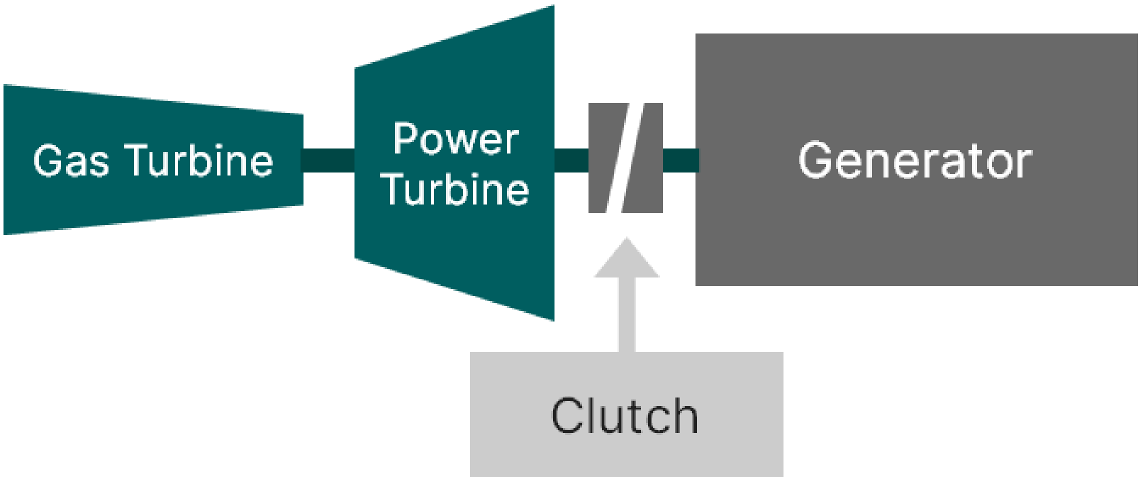
GEV offers a suite of targeted upgrade solutions to support more flexible operation. These upgrades can, for example, improve start times, improve turndown capability, increase efficiency or increase output while maintaining emissions compliance and preserve combustion stability at low loads. These targeted engineering changes, combined with ongoing performance monitoring, enhance asset responsiveness and extend operational usefulness. The upgrades can typically be implemented as part of major overhauls but come at an additional price. GEV has indicated that customers are very interested in these upgrade options that can extend unit life and provide additional operational flexibility. The key challenge is obtaining a revenue stream to justify the cost of the upgrades.

For coal-fired units, GEV said experience from other plants suggests that transitioning to two-shifting operations requires careful consideration of technical issues and operational costs. It significantly impacts efficiency and consumes equipment life. Two-shifting may require some initial upgrades and more frequent inspections impacting operational cost. Overall, two-shifting can provide operational flexibility and responsiveness to market conditions.

Many existing gas turbine-driven generators can be upgraded to add synchronous condensing capability. Typically, a clutch (not always necessary) is added between the prime mover and the generator, and in some cases, a flywheel can also be added to further increase the inertia capability of the generator. The clutch allows the gas turbine to be mechanically disengaged from the generator while the generator remains connected to the grid providing voltage control, inertia and fault current. The feasibility to add synchronous condensing is site-specific and depends on the turbine/generator model and layout. Key engineering considerations for most sites would be lube oil system sufficient for additional clutch, clutch systems design and control system upgrades. Model specific scope is provided below in **Figure 16**, **Figure 17**, and **Figure 18**. Any grid-connected generator is a strong candidate for conversion but there is currently no clear market mechanism to justify synchronous condenser conversion.

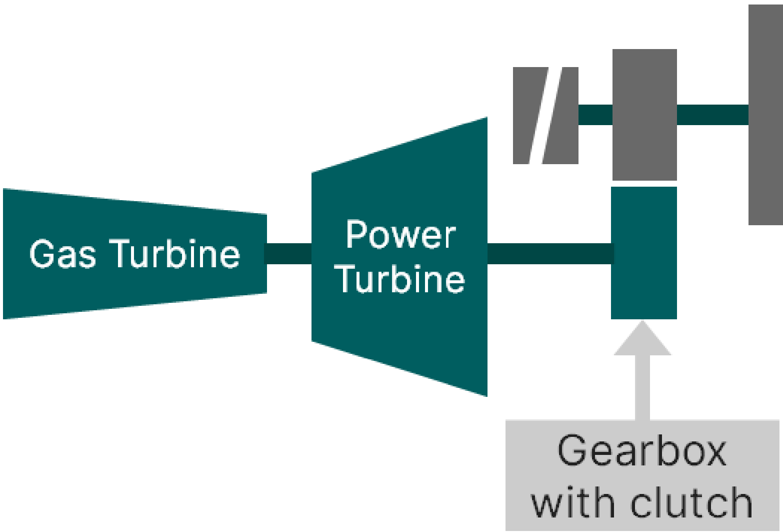
For Frame 9F, GT13E2, and GT26 gas turbine models, moving the generator to provide space for the clutch is likely, as illustrated in **Figure 16**.

Figure 16 Typical large heavy duty gas turbine generator drive train schematic with clutch



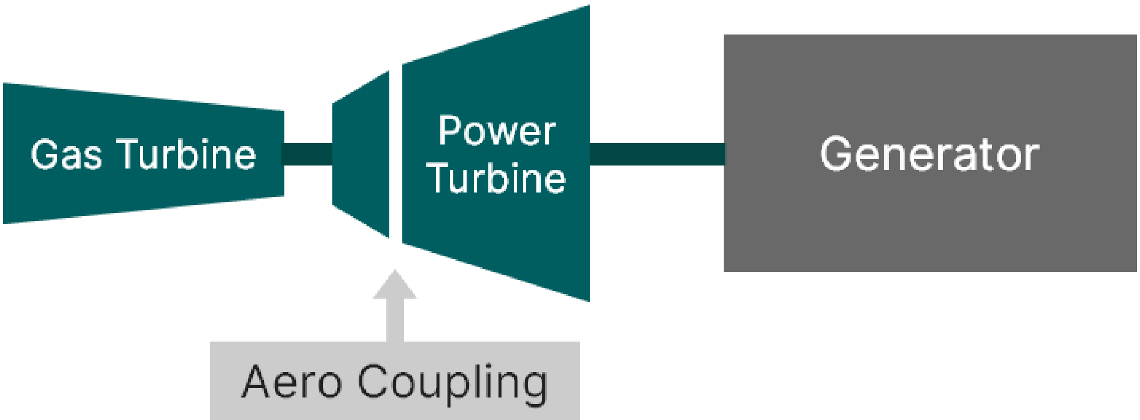
For Frame 6B, Frame 5, LM6000 gas turbine models, replacing or upgrading the gearbox to include the clutch can mitigate the requirement to move the generator to make space for the clutch and avoid the need for civil works, as illustrated in **Figure 17**.

Figure 17 Typical small heavy duty and LM6000 gas turbine generator drive train schematic with clutch



LM2500, shown in **Figure 18**, does not need a clutch. Only the power turbine is connected to the generator which can spin with the generator while the gas turbine is shut down.

Figure 18 Typical LM2500 gas turbine generator drive train schematic, no clutch is required to enable synchronous condensing capability. (LM2500)



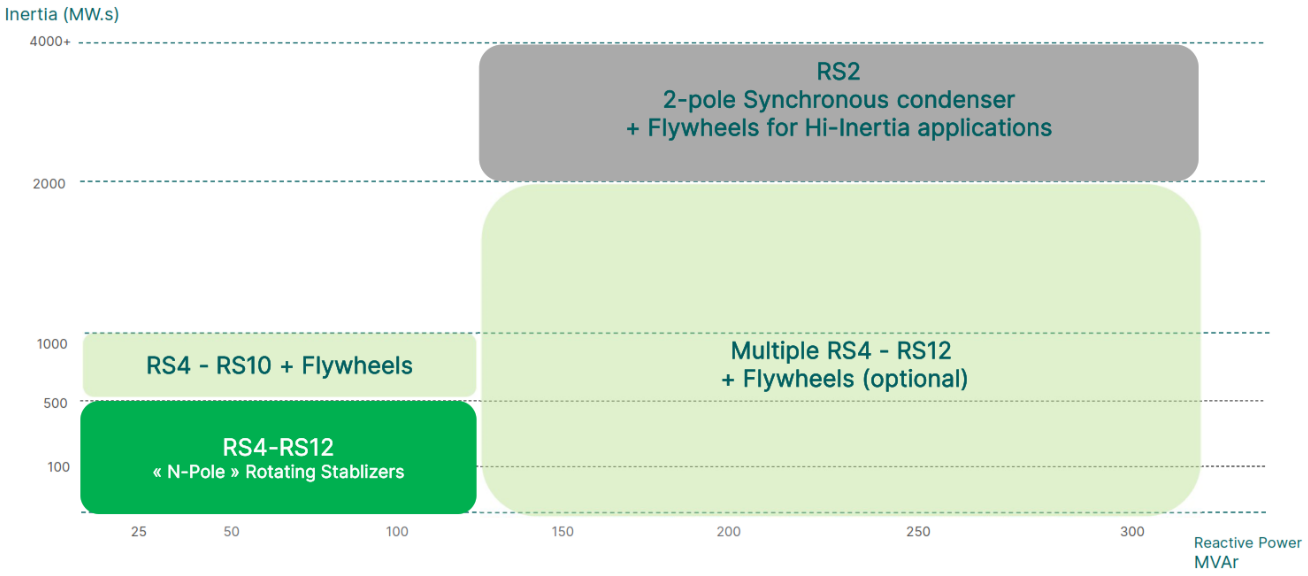
The gas turbine models in **Figure 16** above typically use the generator as a starting device to spin up the turbine prior to ignition. Thus, to go from synchronous condensing mode back to power generation mode, it is normal practice to take the generator offline to coast down that it can re-start the gas turbine.

The gas turbine models in **Figure 17** and **Figure 18** do not use the generator as the starting device. This allows them to re-start the gas turbine with the generator synchronised and in synchronous condensing mode. The gas turbine will engage the clutch at synchronous speed and start to produce active power as load increases. The control system will automatically change from voltage control to active power control.

GEV also provides a comprehensive range of new build syncons with various ranges of reactive power, inertia and short circuit contribution levels to meet most network requirements. Detailed pricing and delivery timelines depend on the final scope of supply. Some components may carry lead times of up to 24 months excluding initial project design.

Figure 19 shows the size range of GEV's syncon portfolio.

Figure 19 Size range of GEV's synchronous condenser portfolio



8.3 Toshiba

Toshiba is a supplier of steam turbine generators (STGs) in the NEM, particularly in New South Wales.

Toshiba provided a written response to the questionnaire. It noted that it was willing to undertake feasibility assessments for the main flexibility enhancements that are being considered at present – for example, steam bypass system enhancements to allow continuous operation (its installed systems are designed for temporary operation as part of start-up management) – but advised that upgrades may be complex and take time to implement. Noting that start-up times and ramp rates were typically based on standard temperature mismatch charts, it also offers assessment on a specific plant basis that may lead to reduced times.

Toshiba also offers an online monitoring system using the 'Internet of Things' (IoT) which may allow faster ramp rates via unit specific cycle and operation analysis.

Toshiba considered end of operational life conversion of its STGs to syncons to be straightforward and, assuming preliminary design stages have been completed, suggested the detailed engineering and site works could be done in 30 to 40 weeks, but with up to two-year delivery period for new components. The cost for a typical conversion was estimated to be AUD $20 million to $35 million, depending on existing unit rating, options to be chosen and inertia requirements (this possibly excludes any other owner's cost.)

8.4 Hitachi

Hitachi is a supplier of standard turbine generators in the NEM, particularly in Queensland.

No formal response was received from Hitachi. Hitachi has provided turbine and generator service/upgrades for its steam turbine generators for some of the units in the past (upgrade of the turbine at Stanwell Power Station from 2003 to 2006, generator rewinds and upgrades at Tarong Power Station from 2003 to 2011, and generator upgrades at Loy Yang B between 2019 and 2024).

Hitachi can supply syncon systems designed for the specific requirements.

8.5 Key findings from OEM engagement

The findings from the OEM engagement are summarised as follows:

- There are a range of upgrade packages on offer to make incremental enhancements to both coal and gas turbine plants.
- A key factor determining the viability of in situ conversion of coal fired plant to syncon operation is the plant condition and residual life.
- As demonstrated through overseas experience, two-shifting is practically achievable, but requires careful consideration of the impact on component life and inspection and maintenance costs.

Individual OEMs made further comments including the following:

- If flexibility is a key criterion, then the design of new CCGT plant (and CCGT conversion of OCGTs) would deviate from the standard design with a small increase in supply cost, an increase in construction cost, and an increase in construction and commissioning risk.
- Adding dual use as a syncon to a new build gas peaking plant is relatively simple and is expected to increase equipment supply cost by only ~5%.
- Converting existing gas turbines to dual mode syncon and generator capability is considered feasible. The conversion engineering depends on the plant configuration and therefore needs to be investigated on a site by site basis.
- When it comes to the practicality and economics of repurposing of retired plant, particularly if the rest of the facility was to be demolished, it may prove more economical to build new syncon units nearby that can take advantage of the existing grid connections from the decommissioned plant.

9 Findings and conclusions

9.1 General findings

The desktop study concluded that availability factors of the combined coal-fired generation fleet have remained relatively stable over the last six years, notwithstanding some variability within individual plants.

There is evidence that station owners or operators are seeking or investigating enhancements to the operational flexibility of the plants in their portfolios, but there is a need to take this further, in particular by enabling operation at a lower minimum output, helping to mitigate MSL issues.

The progressive shutdown of coal-fired plant reduces the certainty of having sufficient large generators connected to the system to manage system strength, inertia and reserves, and introduces the need to understand longer-term outage schedules and expected availability.

One option that may be open to SSSPs is to consider repurposing generators from coal-fired and gas turbine plants. For coal-fired plants, syncons could either be repurposed from spares or from units that are being retired from service. A high-level review of the timeline for conversion of coal-fired plant generators to syncons indicates that conversion could be implemented in as few as seven months from shutdown, provided engineering studies were initiated three to four years prior to shut down, and long lead time components (such as pony motor, flywheel if required) were pre-ordered in advance of the final detailed design. Any syncon conversion would need to be assessed on its own merits to consider its feasibility, risks in the conversion process and ongoing reliability.

9.2 Key findings from station engagement

All the stations commented, to varying extents, on the need for greater co-ordination of outages. For them, this was more around availability of skilled labour and other resources than the impact of multiple simultaneous outages on system security.

For stations that are scheduled for closure in the next few years, the owners noted the complexity of closure and the need to consider, among other things, fuel supply, ash disposal and other services that have lengthy lead-in time. The impacts of late changes could be considerable or may miss the window of opportunity altogether.

All the coal-fired stations emphasised their intention to maintain availability as far reasonably practical given the significant operating changes in the NEM. All coal-fired power stations provided high level details of their maintenance schedules and strategic asset management plans to achieve this, and it was evident that costs to maintain availability are increasing as the assets age.

While most stations have established and secured fuel supplies, a few coal-fired and gas turbine stations are experiencing fuel supply issues, ranging from mine water limitations to limited gas flow rates to maintain operation, as well as the need to purchase gas on the spot market. These constraints have the potential to have flow on impacts on system reliability and operability. Expedient mine life extension approval is important to drive early power station life investment decisions to improve system reliability.

Several of the black coal stations in New South Wales are actively progressing a reduction in MSOL and the capability to either reduce export load to near zero or desynchronise during low demand periods. This would either be by maintaining the boiler at MSOL but bypassing the steam to the condenser, or by taking the boiler off load and boxing up prior to restart (two-shifting). At present, AEMO understands this is not actively being investigated in Queensland given market drivers do not presently sufficiently outweigh the costs and implications for component fatigue.

The brown coal stations in Victoria are also not investigating two-shifting, due to reservations around the flame stability of brown coal and the need to upgrade auxiliary fuel systems. These factors are also influencing investigation of reduced MSOLs.

For those stations considering two-shifting operation, the risk of failing to restart on schedule was a present concern to be overcome, as it has been by stations that developed the capability to reliability and frequently two-shift internationally. Presently the hot start-up times are considered conservative and there is potential to reduce these from, typically, two hours to around 90 minutes. Ratcliffe on Soar Power Station (4 x 500 MW) is said to have required 84 minutes notice to achieve reliable restart.

While most of the coal-fired stations have undertaken turbine upgrades – either optimised to achieve a higher maximum generation, or to enhance efficiency – some units have not had upgrades. However, the commercial benefit in these cases is generally low due to the limited life to closure.

Many of the coal-fired stations are looking at their ramp rates – which are set by a combination of mill start-up times and temperature matching of thick-walled pressure parts – but the potential increases were limited, and this was not seen a high priority.

The coal-fired stations were less inclined to bid for system restart services due to the ongoing cost associated with maintaining the capability to offer these services. This includes black start gas turbines located at some of the coal-fired stations.

The gas turbine stations are operated within the limitations set by the OEMs, and MSOL is mostly limited due to environmental emissions limits. The outage intervals are determined from the equivalent operating hours set by the OEMs for inspections and major overhauls. The uptake of OEM upgrades to enhance operational flexibility seems to be limited due to the additional capital cost with limited return from this capital outlay.

The gas turbine stations have constraints with fuel supply related to either physical infrastructure or significant uncertainties in gas supply due to ongoing issues with availability of gas, cost of gas and future new supplies. This also impacts their ability to operate at baseload for several days if required.

A portion of the coal stations in Queensland and Victoria have TTHL capability, but this does not exist elsewhere.

The larger gas turbine stations (>100 MW) generally cannot offer system restart services as the original design had not allowed for this capability.