Appendix 5: Reserve Products in Electric Markets Around the World (As Provided by ERCOT)

Product Type / Comparison Element	**Outside of U.S.**			**United States**						
	AEMO	**Eirgrid (Ireland)**	**National Grid (United Kingdom)**	**ISO-NE**	**NYISO**	**PJM**	**MISO**	**SPP**	**ERCOT**	**CAISO**
Region Facts	Max Demand 35,796 MW Min Demand 11,892 MW Wind Capacity 11,392 MW Solar Capacity 9,644 MW Rooftop Solar Capacity 19,642 MW	Max Demand 5,577 MW	Max Demand 55 Gigawatts (GW) Min Demand 15 GW Wind and Solar Capacity 35 GW (Includes 2.9 GW of Rooftop solar capacity)	Max Demand 28,130 MW (Aug 2006) Wind Capacity as of Dec 2023: 1,400 MW Solar Capacity mostly Rooftop as of Dec 2023: 6,500 MW	Max Demand 33,956 MW (July 2013) Wind Capacity as of Dec 2023: 2,736 MW Solar Capacity as of Dec 2023: 194.4 MW Rooftop Solar Capacity as of Dec 2023: 5,227 MW	Max Demand 165,563 MW (Summer 2006) Wind Capacity as of Jun 2022: 1,570 MW Solar Capacity as of Jun 2022: 2,665 MW	Max Demand 127.1 GW (7/20/2011) Wind Capacity as of Dec 2023: 30.56 GW Solar Capacity as of Dec 2023: 7.6 GW	Max Demand 56,184 MW (8/21/2023) Wind Capacity as of Jun 2024: 5.4 GW Solar Capacity as of Jun 2024: 396 MW	Max Demand 85,559 MW (8/20/2024) Wind Capacity as of Jun 2024: 39,450 MW Solar Capacity as of Jun 2024: 25,333 MW	Max Demand 44,534 MW (8/16/2023) Wind Capacity as of Aug 2024: 8,352 MW Solar Capacity as of Aug 2024: 19,638 MW Rooftop Solar Capacity as of Aug 2024: 10,000 MW

Product Type / Comparison Element	Outside of U.S.			United States						
	AEMO	**Eirgrid (Ireland)**	**National Grid (United Kingdom)**	**ISO-NE**	**NYISO**	**PJM**	**MISO**	**SPP**	**ERCOT**	**CAISO**
Total AS Products Procured Using Pre-Day Ahead or Day Ahead or Real Time Markets	10[37]	(Current) 10 (AS product suite is in active transition. Products and counts may change in future)	(Current) 20 (AS product suite is in active transition. Products and counts may change in future)	4	3	4	5 or 6	6	5	6 or 7
Regulation Service	Regulation raise and Regulation lower	Primary Frequency Control Secondary Frequency Control	Regulating Reserve changing to Dynamic Regulation and Dynamic Moderation	Regulation	Regulation	Regulation	Regulation	Regulation Up Regulation Down	Regulation Up Regulation Down	Regulation Up Regulation Down

[37] For AEMO, SPP, ERCOT, and CAISO, it's relevant to note that these numbers include the fact that these markets have separate Regulation Up and Regulation Down AS products. The other regions also have Regulation Up and Regulation Down, i.e., Regulation to address frequency deviations in either direction, but they are part of one singular Regulation product.

Product Type / Comparison Element	Outside of U.S.			United States						
	AEMO	Eirgrid (Ireland)	National Grid (United Kingdom)	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Frequency Response		Fast Frequency Response Primary Operating Reserve Secondary Operating Reserve	Dynamic Containment, Static Firm Frequency Response and Dynamic Firm Frequency Response	-	-	-	-	-	Responsive Reserve Service	-

Product Type / Comparison Element		Outside of U.S.			United States						
		AEMO	Eirgrid (Ireland)	National Grid (United Kingdom)	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Contingency Reserve	Spinning	Very fast raise & lower (1 second raise & lower) Fast raise & lower (6 second raise & lower) Slow raise & lower (60 second raise & lower) Delayed raise & lower (5-minute raise & lower)		(Proposed) Quick Reserve (Proposed) Slow Reserve	Ten-Minute Spinning Reserve (TMSR)	Spinning Reserve	Synchronized Reserve (SR)	Spinning Reserve	Spinning Reserve	ECRS	Spinning Reserve

Product Type / Comparison Element		Outside of U.S.			United States						
		AEMO	Eirgrid (Ireland)	National Grid (United Kingdom)	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
	Non-Spinning reserves and supplemental reserves	-	Tertiary Primary Operating Reserve Band 1 Tertiary Operating Reserve Band 2 Replacement Reserve Substitute Reserve Contingency Reserve	Short term operating reserve	Ten-Minute Non-Spinning Reserve (TMNSR) Thirty-Minute Operating Reserve (TMOR)	Non-Spinning reserve	Non-Synchronized Reserve (NSR) Secondary Reserve	Supplemental reserve	Supplemental Reserves	Non-Spin reserve	Non-Spinning Reserve
Ramp Products	Short Horizon	-	(Proposed) Ramping Margin 1 Hour (Proposed) Ramping Margin 3 Hour (Proposed) Ramping Margin 8 Hour	Start up and Hot standby	-	-	-	Up and down Ramp Capability	Ramp Capability Product	ECRS	Flexible Ramping Product–upward and downward reserves
	Longer Horizon							Short-Term Reserve	Uncertainty Product	Non-Spin Reserve	Imbalance Reserve

Appendix 6: Potential Future AS Needs (As Provided by ERCOT)

As the ERCOT Region continues to transform and technology continues to evolve, Ancillary Services are expected to also transform and evolve. *Appendix 4: Changes to AS Methodology between 2016 and 2024* lists the significant changes to the AS Methodology since 2016. Going forward, stakeholders should expect similar advancements to be implemented as needed to meet evolving system needs.

Two topics that have elicited stakeholder discussions regarding possible changes to AS but have not yet been deemed to require new AS products are inertia and the impacts of the addition of new large loads.

Inertia

Inertia is the physical measurement of a power system's potential energy that is stored in the mass of rotating machines, primarily generators. Inertia levels, typically expressed in terms of gigawatt-seconds (GW-s), indicate a power system's ability to resist a change in frequency due to an imbalance in generation and load. As an example, when a generator trips offline suddenly, the inertia in a system prevents the frequency from dropping below 60 Hz too much and too quickly.

Inertia is inherently provided by synchronous generators, such as gas, coal, nuclear, and hydro resources which contain large synchronous rotating masses. Inverter-based resources (IBRs), namely wind, solar, and battery resources, do not have the inherent capability to provide inertia. It has been generally understood that as the resource mix changes to include a greater portion of IBRs and lesser quantities of synchronous generators, inertia will decrease.

ERCOT has calculated a minimum inertia level (known as "critical inertia") of 100 GW-s, which is the quantity of inertia needed to maintain stability. In ERCOT, inertia is typically between 200 GW-s and 400 GW-s depending on the number and size of synchronous generators that are online. Low inertia levels occur during times of low net load when the load is low, IBR generation is relatively high, and very few synchronous generators are online. These conditions usually occur in the spring and fall. The lowest inertia that ERCOT has experienced in the last ten years has been 115 GW-s, which occurred in March 2022.

ERCOT monitors inertia in real-time, and if inertia levels were to approach the critical inertia level, operators would use the RUC process to commit additional synchronous generation, thereby increasing inertia. This process ensures that reliability is maintained, but if ERCOT were to take this action on a regular basis, it may be more efficient to procure the inertia through a new or modified AS product.

ERCOT has not yet needed to use the RUC process to maintain inertia. Additionally, there are several developments that may lessen the chance that ERCOT would experience inertia levels near the critical inertia threshold. These developments include:

1. Minimum load levels have been and are expected to continue to increase due to increasing quantities of data center and oil and gas loads. The higher the minimum load levels, the more likely it is for synchronous generators to remain online, which results in higher inertia on the system. Figure 27 shows that minimum load levels rose significantly over the study period.

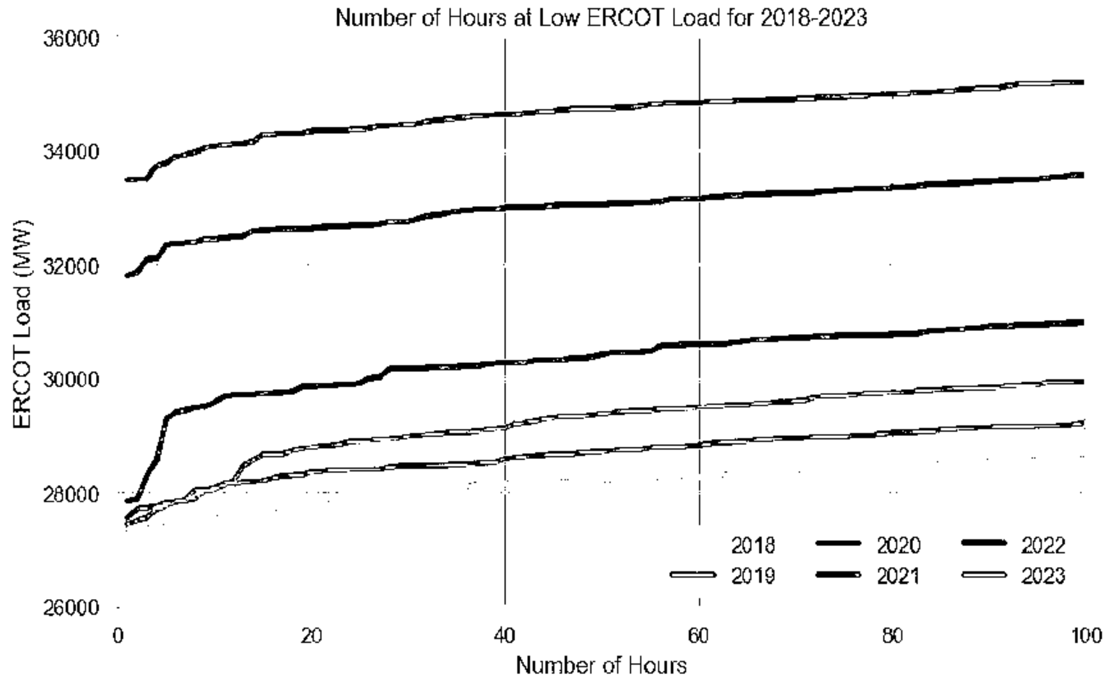

Figure 27 - Number of Hours of Low ERCOT Load for 2018-2023

2. The expected adoption of grid forming inverters is expected to lower the critical inertia level required by synchronous generators in ERCOT. Grid forming inverters are a new type of inverter that has advanced capabilities compared to the inverters on existing IBRs. While grid forming inverters do not provide inertia, they do provide stability when there is an imbalance between load and generation when a generator trips. Grid forming inverters are commercially available for battery energy storage resources, and ERCOT plans to propose grid forming inverter grid code specifications by the end of 2024 to provide guidance to stakeholders.
3. The planned addition of synchronous condensers in ERCOT will increase inertia on the system. Like synchronous generators, synchronous condensers inherently provide inertia. Synchronous condensers are planned to be added at six locations in west Texas by 2027. These synchronous condensers are expected to provide a total of at least 12 GW-s of inertia and are planned to be operated continuously, except for maintenance periods.

Because of these developments, at this time, ERCOT does not see a need to pursue AS product changes to address low inertia levels.

Large Load Related AS Changes

Recently, ERCOT has experienced a notable increase in new loads that are greater than 75 MW in size. These "large loads" present some unique challenges that may need to be addressed by changes to AS. Specifically, there are two challenges that could potentially be mitigated by AS changes and that, if not addressed, may cause reliability issues on the ERCOT system.

1. Some large loads, for example crypto-mining data centers, can quickly change consumption based on changes in ERCOT wholesale prices. If many large loads change their consumption at the same time and in a manner not coordinated with ERCOT, it could cause a significant imbalance between load and generation, which could cause frequency instability on the ERCOT system. This issue could be addressed by mandating those that are able to follow SCED must register as Controllable Load Resources (CLRs) and by establishing ramp rate limitations for large loads that cannot be CLRs, i.e., how fast a large load can change their consumption, or by increasing the quantities of AS that are procured to cover consumption changes by large loads. However, through mid-2024, ERCOT has not observed reliability problems due to large load consumption ramps. Based on this, ERCOT is not currently planning to make any related changes but will continue to monitor the issue.
2. The second challenge is related to how large load equipment responds to system faults, such as lightning strikes. When a fault occurs somewhere on the transmission system, the voltage of the equipment in the immediate vicinity of the fault will spike below normal levels. When this happens, certain voltage sensitive equipment, such as the power supplies of data center servers, will temporarily cease consuming power. This sudden reduction in consumption can cause an imbalance between load and generation, which could cause sudden frequency instability on the ERCOT system. Such an event occurred on the ERCOT system in December 2022 when multiple faults in west Texas caused the loss of 1,600 MW of consumption. In this case, frequency rose to 60.235 Hz, which is relatively high, but it did not cause any significant reliability problems on the ERCOT system. There are several ways this issue could be mitigated, including limiting the quantity of load that can be connected to the transmission system at any single location, constructing transmission system improvements, establishing “voltage ride-through” requirements for large loads, or by creating a new type of AS to preserve “floor room” on generators so that the generators can respond to sudden load-generation imbalances and maintain frequency stability. At this time, ERCOT is not pursing a new type of AS but is proposing to create a planning criterion that could help limit the maximum load loss that occurs during system faults. As the system and ERCOT Market Rules evolve, the need for a new type of AS should be assessed based on ERCOT’s ability to maintain frequency below the levels that trigger NERC compliance issues or generation trips during actual system faults.

Appendix 7: Current Proposed Changes for 2025 Ancillary Services Methodology

Table 7 summarizes ERCOT's proposed changes for the 2025 AS Methodology. These changes are proceeding through the Protocol-defined annual update process and are expected to be considered at the October ERCOT Board meeting.

Table 7 – Summary of Proposed Changes for 2025 Ancillary Services Methodology

AS	Proposed Changes
Regulation	Change methodology for Regulation Service, to the error in forecasting net load that is used to set dispatch target for SCED (i.e. Generation to be Dispatched (GTBD). This aligns the required quantity more closely to the forecast error that drives the need.
RRS	To align with ERCOT's new IFRO from NERC, the minimum RRS-PFR limit for 2025 will change to 1,365 MW. NERC's preliminary BAL-003 Interconnection Frequency Response Obligation (IFRO) for Operating Year (OY) 2025 assessment for ERCOT shows a decrease in ERCOT's IFRO.
ECRS	Change methodology for ERCOT Contingency Reserve Service (ECRS) to (1) Remove the adjustment for risk coverage during sunset hours to be at least 90th percentile, (2) Adjust the frequency recovery portion such that it covers 70% of historic net load and inertia conditions and (3) compute the minimum ECRS requirements as the larger of the capacity needed to recover frequency and capacity needed to support net load forecast errors.
Non-Spin	Change Non-Spin quantities specifically for nighttime (HE23 to HE06) to be computed using 4 Hours Ahead (HA) hourly average net load forecast error. Non-Spin quantities during rest of the hours will be based on 6 HA hourly average net load forecast error (as in 2024). Based on analysis of committed resources and ability to meet forecast errors over past 3.5 yrs.