Filing Receipt

Filing Date - 2024-11-29 10:51:04 AM

Control Number - 56335

Item Number - 8

Report on Dispatchable and Non-Dispatchable Generation Facilities

Responsive to Public Utility Regulatory Act (PURA) §39.1591 (House Bill 1500, 88R)

December 1, 2024

Introduction

Public Utility Regulatory Act (PURA) §39.1591 (House Bill 1500, 88R) requires the Public Utility Commission of Texas (PUCT) to submit a report on costs associated with dispatchable and non-dispatchable generation facilities to the Legislature by December 1 each year. Specifically, the report must provide:

(A) the estimated annual costs incurred by load-serving entities associated with backing up dispatchable and non-dispatchable electric generation facilities to guarantee that a firm amount of electric energy will be available to the ERCOT power grid; and

(B) as calculated by ERCOT, the cumulative annual costs that have been incurred in the ERCOT market to facilitate the transmission of dispatchable and non-dispatchable electricity to load and to interconnect transmission level loads, including a statement of the total cumulative annual costs and of the cumulative annual costs incurred for each type of activity described above.

Part (A) of this report provides the required information for calendar year (CY) 2023 based on data available within ERCOT systems. For part (B), this report offers CY 2023 information provided by ERCOT and transmission service providers (TSP) in response to a request for information issued by PUCT Staff.[1]

The legislation also requires the PUCT to document the progress in implementing PURA Chapter 39, subchapter D requirements related to reliability, resilience and transparency of the electricity market and whether any regulations or ERCOT rules the PUCT has adopted as result of those statutes that have materially improved the reliability, resilience, and transparency of the electricity market. The PUCT's regular status reports on implementation of legislation found in subchapter D are attached as appendices.

Changes in laws or regulations take time to have material impact on the resiliency of grid operations. Whether due to the time it takes to develop and implement new systems software solutions or construct more robust infrastructure, enhancing operational reliability is a multi-year effort. As a result, starting in 2025, Staff will begin a review of subchapter D and provide an update on the status of regulations or ERCOT rules that may have materially improved reliability, resilience, and transparency of the electricity market.

[1] Report on Dispatchable and Non-Dispatchable Generation Facilities - CY 2024, Project No. 56969, *Staff Memo - Report on Dispatchable and Non-Dispatchable Generation Facilities*, AIS Item No. 2 (Aug. 29, 2024).

A. Load-Serving Entities' Annual Costs to Back-up Dispatchable and Non-Dispatchable Electric Generation

ERCOT procures reliability services, which are energy products and services used to maintain grid stability and reliability. Each year, ERCOT – in consultation with market participants and under the authority of the PUCT – determines the minimum amount of each product or service needed for the upcoming calendar year using a risk-based assessment. ERCOT's methodology examines risks to the system's ability to maintain frequency at a steady state of 60 Hz and control system voltage within nominal ranges. Through its settlement systems, ERCOT allocates costs associated with procuring reliability services to qualified scheduling entities (QSEs) based on each QSE's load ratio share. Each QSE assigns these costs to the load serving entities (LSEs) that it represents, such as retail electric providers, electric cooperatives, or municipally owned utilities. LSEs pass these costs on to end-use customers. ERCOT does not have information about how the QSE assigns these costs to LSEs or how LSEs pass these costs on to customers. Each LSE may have different financial or physical hedging arrangements into which ERCOT has no visibility.

Below is a brief explanation of each of the reliability products and services procured by ERCOT and allocated to QSEs based on their load ratio share.

Ancillary Services (AS) are reliability products used to support the transmission of energy to load. These products are purchased by ERCOT to balance supply and demand of electricity on the grid and for mitigating real-time operational issues. A QSE may independently arrange to contract for its share of AS and report those amounts to ERCOT in a process known as self-arrangement. In 2023, QSEs self-arranged approximately 12% of AS, across all hours and AS products. Ancillary services can be provided by qualified generators or consumers (also referred to as 'load'), to increase or decrease the supply of electricity in a matter of minutes or seconds. Resources selected in the day-ahead market (DAM) to provide an ancillary service for a particular hour are paid the clearing price for that service for that hour. These payments are collected from the LSEs. There are four types of AS:

1. **Regulation Services (Reg-Up and Reg-Down)** are provided by resources that can respond to signals from ERCOT to adjust their output or consumption within five seconds to address rapid changes in system frequency.
2. **Responsive Reserve Service (RRS)** is provided by resources that can, within the first few seconds, arrest significant frequency deviations on the grid and, ultimately, help restore system frequency back to 60 Hz. One example of an event that would cause such a deviation is a large generation resource tripping offline.

3. **ERCOT Contingency Reserve Service (ECRS)** is provided by resources that can be available within 10 minutes and provide the service for at least two consecutive hours to cover errors in forecasting or replace deployed reserves.
4. **Non-Spin Reserve Service (Non-Spin)** is provided by resources that can be available within 30 minutes and provide the service for at least four consecutive hours to cover errors in forecasting, respond to forced outages, or replace deployed reserves.

Additional reliability products and services procured by ERCOT to support transmission of energy to load are described below.

Black Start Service (BSS) is provided by qualified generation resources contracted to be ready to start up without the support of the ERCOT transmission grid in the event of a system-wide or partial system outage.

Emergency Response Service (ERS) is provided by qualified generation resources and end-use customers (including aggregations) that are contracted to be deployed by either decreasing demand or increasing supply in the event of an emergency. ERS is procured for two different response times: responding within 10 minutes or responding within 30 minutes. ERCOT awards contracts for ERS four times per year.

Firm Fuel Supply Service (FFSS) is provided by qualified generation resources from November 15 through March 15. The generation resources must maintain sufficient back-up fuel and be able to follow ERCOT dispatch instructions during extreme winter weather if there is a disruption in natural gas supply. FFSS is established to mitigate risks in the natural gas supply chain.

Reliability Must Run Service (RMR) is provided by a resource entity with whom ERCOT contracts for capacity and energy from generation resources that otherwise would not operate and that are deemed necessary to provide voltage support, stability, or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist.

Reliability Unit Commitment (RUC) is a process to ensure that there is adequate resource capacity and ancillary service capacity committed in the proper locations to serve ERCOT's forecasted load. The portion of the RUC settlements (make whole payments to generators) not assigned directly to capacity-short entities is allocated to the QSEs based on load ratio share. The extra revenues clawed back from resources that receive RUC instructions (above their make whole payments) are paid out to QSEs on a load ratio share basis.

Voltage Support Service (VSS) is a service necessary to maintain transmission and distribution voltages on the ERCOT transmission grid within acceptable limits. Currently, no costs were incurred for this service.

Table 1 below delineates the charges allocated to QSEs from the ERCOT settlement systems for reliability services during CY 2023. ERS charges have been evenly allocated across the months of the respective contract periods. The charges reported here do not include any secondary cost impacts borne by the LSEs resulting from reliability deployment price adders. The ancillary services settlement data provided include the AS procured by ERCOT in the DAM and the self-arranged AS valued at DAM market clearing prices for capacity. In 2023, ERCOT had no RMR resources under contract; as a result, no costs were assigned to load.

Table 1: Reliability Services Costs Incurred by Load-Serving Entities ($million, CY 2023)

Month	AS[1]	BSS [1]	ERS[1]	FFSS	RMR Charge	RUC [2]	RUC[3]	VSS	TOTAL
Jan	$26.4	$0.6	$5.0	$8.0	$0.0	$0.0	($0.8)	$0.0	$39.1
Feb	$29.9	$0.5	$5.0	$9.7	$0.0	$0.0	($0.2)	$0.0	$44.9
Mar	$45.7	$0.6	$5.0	$4.7	$0.0	$0.0	($0.2)	$0.0	$55.8
Apr	$44.2	$0.5	$1.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$45.7
May	$57.2	$0.6	$1.0	$0.0	$0.0	$0.0	($0.4)	$0.0	$58.4
Jun	$310.7	$0.5	$6.3	$0.0	$0.0	$0.0	($0.1)	$0.0	$317.4
Jul	$137.1	$0.6	$6.3	$0.0	$0.0	$0.0	($0.2)	$0.0	$143.8
Aug	$909.7	$0.6	$6.3	$0.0	$0.0	$0.0	($0.4)	$0.0	$916.2
Sep	$177.4	$0.5	$6.3	$0.0	$0.0	$0.0	($1.0)	$0.0	$183.2
Oct	$68.4	$0.6	$2.6	$0.0	$0.0	$0.0	($0.2)	$0.0	$71.3
Nov	$49.2	$0.5	$2.6	$3.5	$0.0	$0.0	($0.0)	$0.0	$55.8
Dec	$18.4	$0.6	$8.8	$7.3	$0.0	$0.0	$0.0	$0.0	$35.0
TOTAL	$1,874.1	$6.6	$56.1	$33.2	$0.0	$0.0	($3.5)	$0.0	$1,966.6

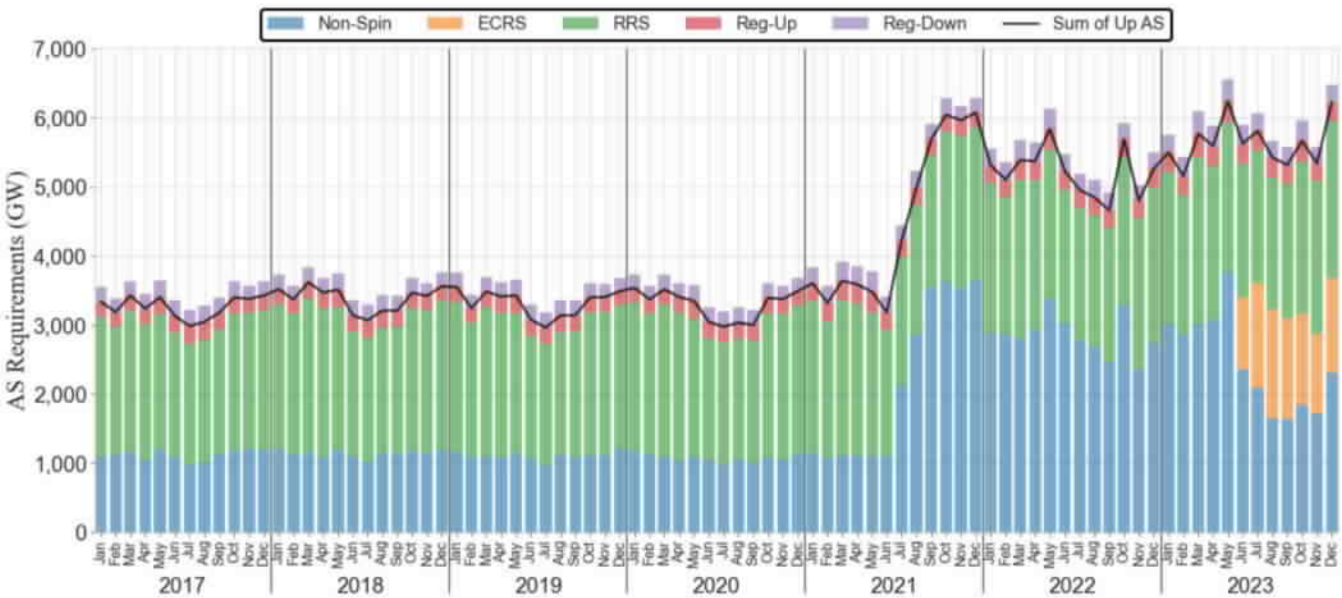
Notes: 1- Settlements, 2- Make Whole Uplift Charge, 3 - Claw Back Allocated to Load

The remainder of this section of the report restricts attention to ancillary services, which accounted for more than 95 percent of the total costs in CY 2023.

Qualitative Review of Operational Risks and AS Quantities

ERCOT annually determines minimum quantities of each type of AS required to mitigate real-time operational issues. The calculation methodology includes a statistical analysis of the historical drivers for AS while factoring in expected system changes that may impact the needed quantities. Figure 1 below displays the total monthly ancillary service procurements from January 2017 through December 2023, broken down by AS type. The most notable change over this period was an increase in the quantities of some types of AS beginning in the latter half of 2021. This change reflects an operational posture that ERCOT adopted beginning July 2021 that requires more operating reserves to be online in real-time to effectively avoid entering emergency operations.

Figure 1: Total Monthly Ancillary Service Requirements (GW)



The risks that each AS covers and the adjustments to AS quantities that have been implemented to account for changes in the factors that drive each of these risks are examined below. Many of these services are designed to address risks and uncertainties related to net load, which is the system load for a given period less the amount of generation produced by photovoltaic generation resources (PVGRs) and wind generation resources (WGRs) for the same period.

Below is a brief explanation of the risks and uncertainties that each AS addresses.

Regulation Services are procured to cover risks associated with uncertainty from net load ramp, which is defined as changes in net load between consecutive time intervals. Quantities are primarily determined from an assessment of historical net-load ramp during the same month in the previous two years. Quantities may also be adjusted based upon annual incremental changes in installed wind and solar generation capacity.

Responsive Reserve Service is procured to ensure that sufficient capacity is available to respond to changes in frequency resulting from unit trips. The primary determinant of RRS quantities is the combined capacity of the power region's two largest units, both of which are dispatchable generation resources.

ERCOT Contingency Reserve Service is primarily procured to cover risks associated with intra-hour net load uncertainty, with quantities determined based on an analysis of historical intra-hour net load uncertainty during the same month and hour in the previous two years. Quantities may also be adjusted based on incremental growth in solar capacity. Additionally, ECRS may be deployed to restore frequency following a significant frequency deviation resulting, for example, from a large generation unit trip.

Non-Spin Reserve Service is procured to cover risks associated with hourly net load uncertainty, with quantities determined based on an analysis of historical, hourly net load uncertainty from the same month in the previous three years.

Changes in AS Costs Over Time

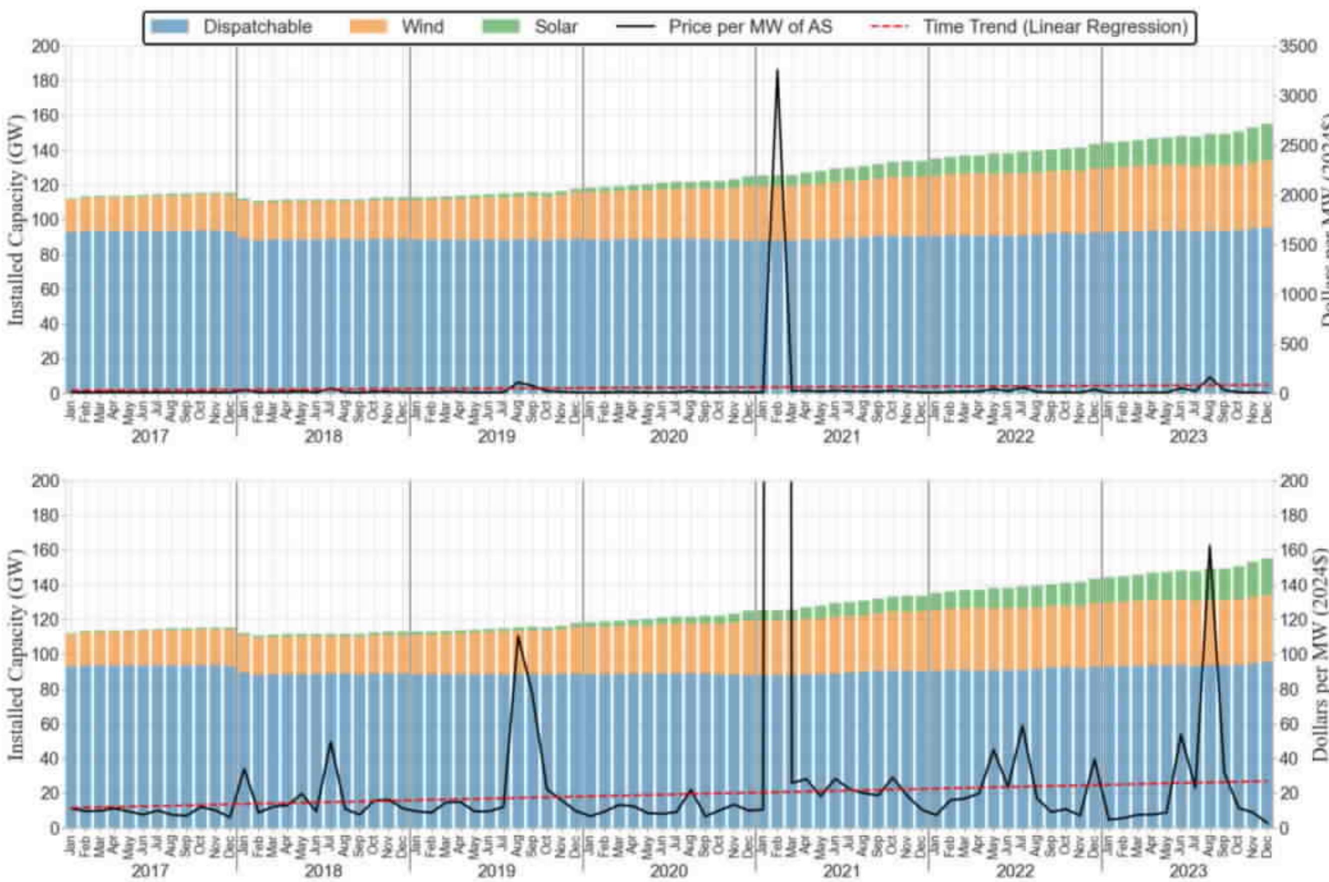
This section examines how AS costs have changed over time and whether any relationship exists between AS costs and installed capacity of non-dispatchable generation resources. Despite the fact that some AS quantities are adjusted to account for incremental growth in non-dispatchable capacity on the system and there has been considerable growth in the amount of non-dispatchable capacity in recent years, AS costs have not substantially increased on a dollar-per-MW basis, on average, during the period examined in this report (January 2017 through December 2023).

Figure 2 includes two graphs displaying total installed capacity, broken down by dispatchable, wind, and solar resources, and the total monthly cost of AS per MW procured from January 2017 through December 2023. The top graph in this figure is zoomed out to a scale that allows it to display all the data. Because of the substantial impacts of winter storm Uri, February 2021 is a considerable outlier in terms of total monthly AS costs. For this reason, the second graph is a zoomed in version of the top graph at a scale that provides a better picture of the AS cost data in all other months.

Each graph in this figure also includes a linear regression trend line that describes the average change in monthly AS costs over time on a dollars-per-MW basis. The regression time trend line displayed in the second graph (which is estimated on a subset of the data that excludes February 2021) indicates that AS costs have increased, on average, over this period. However, the estimated effect is only marginally significant (p-value = 0.071), and the magnitude of this increase is relatively modest at approximately $2.2/MW annually. A regression analysis estimating the effect of an additional GW of installed non-dispatchable capacity on the price per MW of AS indicates a marginally significant (p-value = 0.092) increase of $0.35/MW of AS. Figure 2 also reveals that AS prices were unusually high in August 2023. Repeating similar regression analyses on a further restricted dataset that excludes August 2023 (in addition to February 2021), reveals a statistically insignificant (p-value = 0.309) annual increase in AS costs of $0.93/MW, on average, over this period and a statistically insignificant (p-value = 0.470) increase of $0.11/MW of AS per GW of additional installed non-dispatchable capacity.

In summary, while these analyses indicate that AS costs have moderately increased over time, on average, they do not establish a clear link between AS costs and the amount of non-dispatchable capacity on the system.

Figure 2: Installed Capacities and Monthly AS Costs ($ per MW)



Notes:

1. Dollar values are adjusted to 2024 dollars using U.S. Bureau of Labor Statistics Consumer Price Index (CPI) data.
2. The regression line in the first graph is estimated using all data points, while the regression line in the second graph is estimated on a restricted dataset that excludes February 2021 to eliminate the impact of this outlier.

As discussed under the qualitative review section, ERCOT procures AS to manage a varied set of system risks. This includes, but is not limited to, the risk of unit trips (for all generator types) as well as the risk of under-forecasting net load associated with variability of load and non-dispatchable resources that are weather dependent and prone to variability. It is important to note that regardless of the original intent for which the AS was procured, ERCOT may use an AS for any type of contingency faced in real time operations based on the underlying technical capabilities of the resources providing that AS.

The determination of some portion of AS quantities involves adjustments to account for incremental changes in the resource mix and the associated changes in the variability and uncertainty on the grid. However, AS quantities are not, by design, determined directly based on resource type. Additionally, uncertainty related to net load may inherently involve non-dispatchable resources but could as easily be attributed to load forecast error or dispatchable resource under-performance. As such, clear segregation of AS costs between dispatchable and non-dispatchable resources is inherently difficult. However, to comply with PURA §39.1591 (1) (A), Staff presents two approaches that attempt to disaggregate AS costs between three distinct categories: (i) dispatchable, (ii) non-dispatchable, and (iii) load. The following sections present estimates of the costs that can be allocated to each category under these approaches and discuss the short comings of each approach.

I. AS Costs Distributed Based on Real-Time Generation Mix

This approach retroactively compares the AS quantities procured with proportions of the total amount of energy generated in real-time by respective resource types that the AS were backing up. Table 2 reports the results of this distribution methodology, which attributes 78.9% of overall AS costs to dispatchable generation and 21.1% to non-dispatchable resources. This approach, however, abstracts away some important aspects of how AS are determined and procured. First, AS quantities are determined in advance based upon historical analyses of the risks each service is designed to address and forecasts of future conditions. Second, some of the risks inherent to the system at any point in time are also driven by load uncertainty and fluctuations. This approach does not account for the impacts of forecasts, and it assigns all costs either to dispatchable or non-dispatchable generation, ignoring the effect that *load variability* has on AS costs altogether. The approach described under section II attempts to account for all three of these factors.

As shown in Table 2, a majority of all energy generated during 2023 came from dispatchable resources. Total energy generated aligns closely with the proportions of overall installed generation capacity in ERCOT. In December 2023, there was approximately 155 GW of total installed capacity on the system, with nearly 95 GW of dispatchable resources and 60 GW from non-dispatchable resources. Therefore, if annual costs were, alternatively, disaggregated according to the proportion of overall capacity from each category of resources, the results would likely be relatively similar.

Table 2: Ancillary Service Costs Distributed Based on Real-Time Generation ($million, CY 2023)

Month	Regulation	RRS	ECRS	Non-Spin	All AS	DG (%)	NDG (%)	DG	NDG
Jan	$3.5	$8.8	$0.0	$14.1	$26.4	61.6	38.4	$18.7	$7.7
Feb	$5.7	$7.6	$0.0	$16.6	$29.9	61.7	38.3	$21.4	$8.5
Mar	$6.3	$15.2	$0.0	$24.2	$45.7	58.9	41.1	$31.0	$14.6
Apr	$5.8	$13.7	$0.0	$24.6	$44.2	58.6	41.4	$29.2	$15.0
May	$3.9	$8.7	$0.0	$44.6	$57.2	71.4	28.6	$42.1	$15.1
Jun	$16.0	$74.3	$112.2	$108.1	$310.7	72.8	27.3	$239.1	$71.6
Jul	$8.4	$34.9	$58.2	$35.7	$137.1	72.9	27.1	$104.9	$32.2
Aug	$86.0	$253.4	$437.9	$132.3	$909.7	76.5	23.5	$745.0	$164.7
Sep	$20.7	$62.3	$65.8	$28.6	$177.4	75.7	24.3	$143.7	$33.7
Oct	$7.2	$23.7	$22.3	$15.1	$68.4	68.1	32.0	$52.5	$15.9
Nov	$3.8	$17.1	$12.8	$15.4	$49.2	69.2	30.9	$38.9	$10.3
Dec	$1.7	$5.7	$4.5	$6.5	$18.4	65.3	34.7	$12.6	$5.8
TOTAL	$169.2	$525.3	$713.7	$466.0	$1,874.1	68.6%	31.4%	$1,479.1	$395.0

Notes: DG = Dispatchable generation, NDG = Non-dispatchable generation

II. AS Costs Distributed Based on Forecasted Conditions and Covered Risks

This subsection discusses an alternative methodology that accounts for both wind and solar forecasting and load variability aspects of AS quantity determination. This approach disaggregates the costs associated with each AS into three categories–dispatchable (D), non-dispatchable (ND), or load (L)–based upon the types of risks that a product is intended to address and the discrepancies between forecasted and actual conditions.

Below is a brief description of how the cost of each AS is broken down into these categories.

Regulation Services – As discussed above, this service covers risks associated with variability in net load ramp. For each five-minute interval, the total error between forecast and actual net load ramp is calculated. This error is then split into load and non-dispatchable proportions based upon the amount that the ramp error of each category contributes to the overall net load ramp error. These five-minute values are averaged within each hour and costs for that hour are distributed between the load and non-dispatchable categories based on these average hourly proportions.

Responsive Reserve Service - Because the primary determinant of RRS quantities is the capacity of the two largest contingencies on the system, both of which are dispatchable generation resources, the entirety of RRS costs is assigned to the dispatchable category.

ERCOT Contingency Reserve Service– This service is procured to cover risks and uncertainty associated with intra-hour net load variability. For each hour, total net load error is calculated based on the difference between actual and 30-minute ahead forecasts of load, wind, and solar. This error is then split between load and non-dispatchable proportions based upon the amount that the error of each category contributes to the overall net load error. Costs for that hour are then distributed to the load and non-dispatchable categories based on these hourly proportions.

Non-Spin Reserve Service - Some portion of Non-Spin quantities are procured to account for the risk of forced unit outages, and the remainder is procured to cover risk associated with hourly net load uncertainty. For each hour, total net load error is calculated based on the difference between actual and six-hour ahead forecasts of load, wind, and solar. This error is then split between load and non-dispatchable proportions based upon the amount that the error of each category contributes to the overall net load error. The portion of costs associated with the forced outage adjustment is assigned entirely to the dispatchable category, while the remaining costs, which are associated with net load uncertainty, are distributed to the load and non-dispatchable categories based on the proportion of net load error attributable to each.

Table 3 reports the results of this cost distribution methodology. Overall, this approach results in 23.4% of costs being distributed to load, 34.6% distributed to dispatchable, and 42.0% distributed to non-dispatchable. This table also includes the relevant distribution totals and percentages for each individual service. It is noteworthy that approximately 47.9% of the total costs distributed to the load category and 64.0% of the total costs distributed to the non-dispatchable category were from ECRS, a new service launched in June 2023.

Table 3: Ancillary Service Costs Distributed Based on Associated Risks ($million, CY 2023)

Month	Regulation		RRS	ECRS		Non-Spin			All AS			
	L	ND	D	L	ND	L	D	ND	L	D	ND	Total
Jan	$1.2	$2.2	$8.8	$0.0	$0.0	$5.0	$2.4	$6.7	$6.2	$11.2	$9.0	$26.4
Feb	$1.8	$3.9	$7.6	$0.0	$0.0	$7.3	$2.8	$6.5	$9.2	$10.4	$10.3	$29.9
Mar	$2.1	$4.2	$15.2	$0.0	$0.0	$9.9	$4.3	$10.0	$11.9	$19.5	$14.3	$45.7
Apr	$1.8	$4.1	$13.7	$0.0	$0.0	$7.8	$4.8	$12.0	$9.6	$18.5	$16.1	$44.2
May	$1.3	$2.6	$8.7	$0.0	$0.0	$15.4	$8.4	$20.8	$16.8	$17.1	$23.4	$57.2
Jun	$4.8	$11.2	$74.3	$26.2	$86.1	$44.6	$33.5	$30.1	$75.5	$107.8	$127.4	$310.7
Jul	$2.8	$5.6	$34.9	$15.8	$42.3	$13.6	$9.4	$12.7	$32.2	$44.3	$60.6	$137.1
Aug	$29.1	$56.9	$253.4	$130.2	$307.7	$48.1	$36.4	$47.9	$207.4	$289.7	$412.6	$909.7
Sep	$6.9	$13.8	$62.3	$20.1	$45.7	$7.2	$9.4	$12.1	$34.1	$71.6	$71.6	$177.4
Oct	$2.6	$4.7	$23.7	$10.3	$12.0	$5.0	$5.0	$5.1	$17.8	$28.8	$21.8	$68.4
Nov	$1.6	$2.2	$17.1	$5.6	$7.2	$5.3	$5.4	$4.7	$12.5	$22.6	$14.1	$49.2
Dec	$0.6	$1.1	$5.7	$1.6	$2.9	$2.4	$1.4	$2.6	$4.6	$7.1	$6.6	$18.4
TOTAL	$56.7	$112.5	$525.3	$209.8	$503.9	$171.5	$123.2	$171.2	$438.0	$648.5	$787.6	$1,874.1
Pct.	33.5%	66.5%	100%	29.4%	70.6%	36.8%	26.4%	36.7%	23.4%	34.6%	42.0%	100.0%

Although this cost distribution methodology improves upon the previous approach by better accounting for both the impacts of load and uncertainty on AS procurement quantities, it also has its shortcomings. Some AS products are procured to address multiple risks that may be related with different categories, and it is difficult to clearly disaggregate these quantities. For example, ECRS can be used in real time to address frequency deviations following large unit trips, and this portion of the quantity procured could plausibly be assigned to the dispatchable category. Therefore, while this method provides a better approach to distributing costs among these three categories, it is unable to fully account for every aspect of how AS quantities are determined.

B. Annual Costs for Transmission of Dispatchable and Non-dispatchable Electricity to Load

Annual costs associated with transmission of electricity comprises costs associated with generation resource and load interconnections and costs associated with the use of bulk electric transmission network to deliver power from generators to loads.

In 2023, the total cost of transmission buildout to meet the system reliability and economic needs, was approximately $1.6 billion, as reported by TSPs to ERCOT in the *Transmission Project and Information Tracking (TPIT)* report. TPIT is used to track the status of transmission level projects (60 kV and above) that have a material impact to the flow of power in the ERCOT system. ERCOT, however, does not have access to direct costs for both generation and load interconnection buildout. Consequently, Staff issued a request for information (RFI) to collect direct annual costs to interconnect generation and transmission level load from all TSPs in the ERCOT region. In response to the Staff RFI, the ERCOT TSPs provided direct interconnection costs from 2019 onwards. Information for prior years can be accessed in Project No. 56969. This section of the report summarizes the TSP responses to the RFI to provide 2023 annual costs for interconnecting generation resources by resource type and the cost to interconnect transmission-level loads in compliance with PURA §39.1591(1) (B).

In 2023, the total cost of bulk transmission network buildout (excluding the load and generation interconnection) was approximately $1.16 billion. The ERCOT bulk transmission network is used to transmit energy from all available energy resource types to all loads. Hence, it is not possible to accurately allocate or assign bulk transmission network costs to a particular resource type or load.

However, transmission interconnection costs for generation resources can be broken down by resource type.

Table 4 provides a summary of generation resources interconnected to the ERCOT grid during CY 2023. A total of 11,273 MW of generation resources were interconnected to the grid, with interconnection costs approved in rate proceedings totaling $293.18 million. To segregate resources into dispatchable and non-dispatchable categories, all wind and solar generation resources were considered as non-dispatchable resource type. However, for any wind or solar generation resource sharing location with battery or storage resource with battery or storage capacity greater than 10% of the non-dispatchable generation capacity, the full capacity was considered as dispatchable. All conventional generation types and storage or battery resources were considered as dispatchable. The total costs in the table below also include any generation interconnection with multiple energization dates spanning between 2023 and the year prior.

Table 4: Generation Interconnection Cost ($million, CY 2023)

Generator Dispatch Type	Nameplate Capacity (MW)	Transmission Line (miles)	Interconnection costs			
			Estimated	Approved in rate proceeding		
				Transmission Line Built Out	Transmission Upgrades	Total Cost
Dispatchable	3,728	5.62	$84.07	$19.86	$48.86	$68.72
Non- Dispatchable	7,545	31.15	$268.85	$74.08	$150.38	$224.46
Total	11,273	-	$352.92	$93.94	$199.24	$293.18

In 2023, 22 transmission-level loads were interconnected at various voltage levels across various TSPs. The total interconnection costs for these loads that were approved in rate proceedings was $81.49 million, which was made up of $50.91 million for line build out and $30.58 million for upgrades. Table 5, below, provides a summary of transmission-level load interconnection cost broken down by voltage level.

Table 5: Transmission-Level Load Interconnection Cost ($million, CY 2023)

Voltage Level (kV)	Transmission Line (miles)	Interconnection costs			
		Estimated	Approved in rate proceeding		
			Transmission Line Built Out	Transmission Upgrades	Total Cost
69	0.40	$0.00	$0.00	$0.00	$0.00
138	22.85	$91.04	$49.67	$30.58	$80.25
345	0.21	$1.28	$1.24	$0.00	$1.24
Total	-	$92.32	$50.91	$30.58	$81.49

Table 6, below, provides a breakdown of generation resource types interconnected to the ERCOT grid during CY 2023. Some projects in this table have associated costs of $0.00 because they have not been submitted for recovery in a rate proceeding.

Table 6: Generation Interconnection Cost by Resource Type ($million, CY 2023)

Generator Type	Dispatch Type	Nameplate Capacity (MW)	Voltage Level (kV)	Transmission Line (miles)	Interconnection costs		
					Estimated	Approved in rate proceeding	
						Transmission Line Built out	Transmission Upgrades
Gas	D	408	138	0.900	$16.50	$5.49	$6.72
Gas	D	539	138	0.120	$1.14	$0.14	$1.03
Battery	D	63	69	0.102	$2.10	$0.77	$1.72
Battery	D	239	345	0.160	-	$1.08	$4.28
Battery	D	310	138	0.040	$3.34	$3.36	-
Battery	D	100	138	0.050	$1.36	$1.49	-
Battery	D	175	138	0.050	$3.38	$3.24	-
Other	D	150	138	<0.1	$2.10	$0.00	$2.10
Storage	D	150	345	0.000	$0.00	$0.00	$0.00
Storage	D	221	345	0.000	$4.48	-	$4.48
Storage	D	30	345	0.000	$0.00	-	$0.00
Storage	D	151	138	0.000	$0.00	-	$0.00
Storage	D	101	345	0.000	$0.00	-	$0.00
Solar and Battery	D	187	138	<0.1	$12.96	$0.00	$12.96
Solar and Battery	D	203	138	<0.1	$5.29	$0.00	$5.29
Solar and Storage	D	409	345	0.700	$14.57	$4.29	$10.28
Wind and Storage	D	292	345	3.500	$16.84	$0.00	$0.00
Solar	ND	241	138	<0.1	$8.11	$0.00	$8.11
Solar	ND	203	345	0.200	$0.00	$0.00	$0.00
Solar	ND	201	345	0.340	$0.00	$0.00	$0.00
Solar	ND	155	345	0.300	$6.99	$1.21	$5.78
Solar	ND	600	345	0.300	$9.30	$0.00	$5.08
Solar	ND	240	345	0.200	$10.42	$2.27	$8.15
Solar	ND	81	138	0.580	$6.39	$2.25	$4.14
Solar	ND	323	345	1.120	$3.10	$3.10	-
Solar	ND	514	345	0.300	$12.30	$1.57	$10.73
Solar	ND	452	345	0.100	$17.78	$3.26	$0.76
Solar	ND	254	345	1.340	$10.62	$3.66	$6.96
Solar	ND	29	138	0.200	$1.02	$1.02	$0.00
Solar	ND	253	345	1.840	$11.85	$4.17	$7.68
Solar	ND	204	138	0.500	$3.69	$1.25	$2.44
Solar	ND	260	138	0.000	$0.98	-	-
Solar	ND	320	345	1.650	$27.37	$7.87	$19.50
Solar	ND	254	345	0.400	$0.00	$0.00	$0.00
Solar	ND	50	138	0.310	$5.44	$0.92	$4.52
Solar	ND	245	345	0.100	$8.48	$1.21	$7.27
Solar	ND	252	138	0.700	$6.38	$1.81	$4.57
Solar	ND	252	345	0.100	$31.17	$3.35	$26.83
Solar	ND	200	138	0.700	$11.54	$4.10	$7.41
Solar	ND	252	345	0.091	$3.61	$1.03	$2.61
Wind	ND	182	138	0.000	$0.18	-	$0.18
Wind	ND	309	138	0.280	$0.00	$0.00	$0.00
Wind	ND	293	345	17.000	$47.69	$30.05	$17.64
Wind	ND	531	345	0.100	$0.00	$0.00	$0.00
Wind	ND	140	138	0.100	$0.00	$0.00	$0.00
Wind	ND	255	345	2.300	$24.44	$0.00	$0.00
Total		11,273			$352.92	**$93.94**	**$199.24**

Table 7, below, provides a breakdown of transmission-level loads interconnected to the grid along with associated costs recovered in a rate proceeding. Some projects in this table have associated costs of $0.00 because these have not been submitted for recovery in a rate proceeding.

Table 7: Transmission-Level Load Interconnection Cost by Voltage Level ($million, CY 2023)

Voltage Level (kV)	Transmission Line (miles)	Interconnection Costs		
			Approved in rate proceeding	
		Estimated	Transmission Line Built out	Transmission upgrades
138	0.024	$7.00	($0.48)[1]	$0.01
138	0.1	$3.11	($0.21)[1]	($0.01)[1]
345	0.21	$1.28	$1.24	$0.00
138	0.5	$0.00	$0.00	$0.00
138	0.15	$0.38	$0.38	$0.00
138	0.17	$2.26	$1.68	$0.59
138	0.81	$1.87	$1.87	$0.00
138	0.00	$0.00	$0.00	$0.00
138	0.03	$2.01	$1.42	$0.59
138	0.30	$3.68	$2.01	$1.66
138	0.50	$0.00	$0.00	$0.00
138	0.20	$2.90	$2.16	$0.74
138	0.40	$6.63	$0.91	$5.72
138	0.70	$2.12	$1.70	$0.42
138	0.50	$4.06	$2.05	$2.02
138	0.10	$1.33	$1.33	$0.00
138	0.00	$0.00	$0.00	$0.00
138	1.00	$4.07	$1.71	$2.36
138	15.72	$34.60	$20.54	$14.06
69	0.40	$0.00	$0.00	$0.00
138	0.00	$3.39	$0.97[2]	$2.42
138	1.67	$11.62	$11.62	-
Total		$92.32	**$50.91**	**$30.58**

Notes:1- Correction or reallocation of costs, 2- There was no new line buildout associated with this project but there were line costs associated with building a new point of delivery in an existing transmission line to provide service to the customer.

The 2023 interconnection costs above are already, or will be, included in wholesale transmission rates applicable to ratepayers across ERCOT, to be collected over a span of years. As of March 2024, the total wholesale transmission charges in ERCOT were approximately $5.6 billion per year. This represents an eight percent increase year-over-year. The aggregate effective annual ERCOT wide postage stamp transmission rate as of March 2024 was approximately $66.8 per kW.

Appendices

- 88th Legislative Session PUCT Status Report -PowerPoint Presentation
- 87th Legislative Session PUCT Status Report -PowerPoint Presentation

See an up-to-date version of the Status Report here.