2022 Zonal Reliability Study

Final Report

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PREPARED FOR

Electric Reliability Council of Texas ("ERCOT")

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TABLE OF CONTENTS

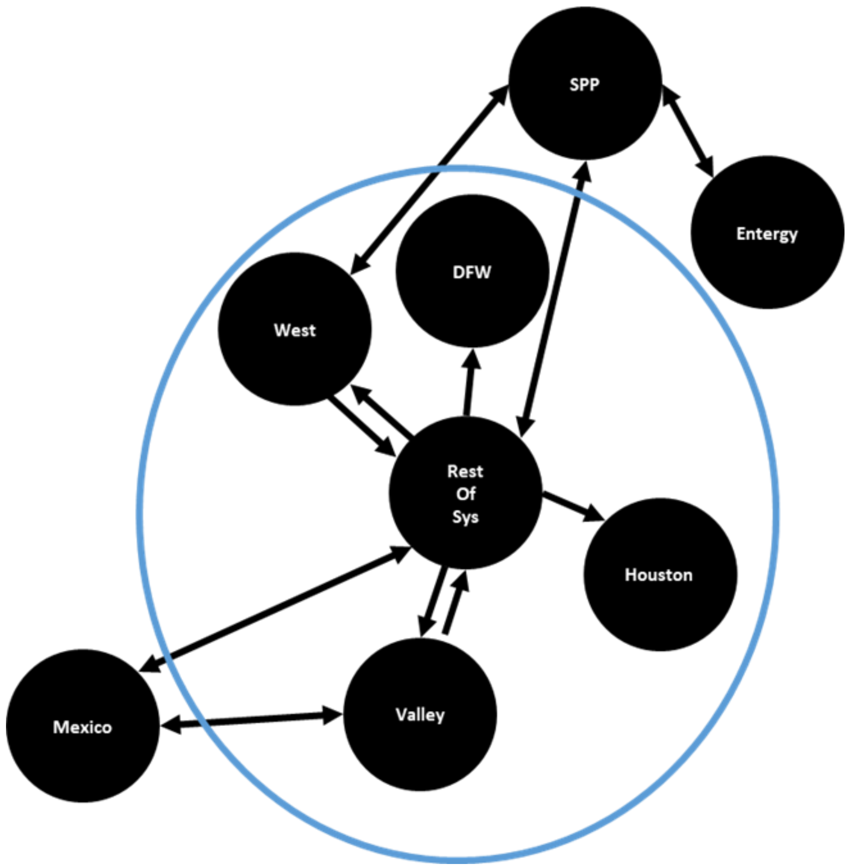
TABLE OF FIGURES

TABLE OF TABLES

EXECUTIVE SUMMARY

A zonal reliability study was performed using Astrapé's proprietary model, SERVM. The SERVM model was transformed from a copper sheet model to a multi-zonal ERCOT model. Zonal reliability was calculated for two study years, 2023 and 2026, with projected renewable and conventional portfolios by zone. The topology for this study was developed by ERCOT Transmission Planning staff and is shown in Figure ES1. The transmission limits remained the same between both study years.

Figure ES1. Study Topology



While the transmission system in actual practice is much more dynamic than represented in this analysis, the input development was intended to approximate the impact of realistic constraints between major areas within ERCOT during high load periods. The imposition of internal transmission constraints had significant implications for projected reliability within ERCOT. The first stage of analysis was to tune the no-constraint case to 1 day in 10 years Loss of Load Expectation (0.1 LOLE) by removing 1,610 MW of conventional capacity from the Rest of System zone for the 2023 study year. The 2026 study as found was already at 0.1 LOLE, so no conventional capacity was removed from the 2026 study year. Once the base case was tuned, the transmission constraints were imposed, and reliability was re-examined. The results demonstrated that even zones 'Rest of System' and 'West' that had high reserve margins showed an increase in LOLE as the diversity in loads, renewable profiles, and generator outages among all zones that contributes to reliability in the unconstrained case are sometimes inaccessible when limits are recognized in the constrained case. Base and change case reliability are shown in Table ES1.

Table ES1. Base Case and Transmission Constrained Case Results

Transmission Group	Region	LOLE (events/year)	
		2023 Study Year	2026 Study Year
Copper Sheet	Aggregate	0.102	0.097
	Dallas	0.102	0.093
	Houston	0.102	0.097
	Rest Of System	0.098	0.097
	Valley	0.101	0.095
	West	0.101	0.096
Constrained	Aggregate	2.033	1.625
	Dallas	0.284	0.321
	Houston	0.172	0.304
	Rest Of System	0.203	0.170
	Valley	1.921	1.288
	West	0.204	0.172

Two tests were performed to understand how sensitive reliability is to both installed generation in each zone and the size of the constraints between each zone. Tables ES2 and ES3 show the required incremental transmission capability (relaxations were bidirectional) or generation capacity to meet 0.1 LOLE in all zones for the 2023 and 2026 study years, respectively.

Table ES2. 2023 Study Year Results to Achieve 0.1 LOLE by Zone

Region	Perfect Capacity Addition/Removal (MW)	Transmission Constraint Relaxation (MW)
Dallas	3,750	2,500
Houston	-150	2,500
Rest of System	-300	2,500
Valley	500	1,500
West	-300	2,500

Table ES3. 2026 Study Year Results to Achieve 0.1 LOLE by Zone

Region	Perfect Capacity Addition/Removal (MW)	Transmission Constraint Relaxation (MW)
Dallas	3,500	3,000
Houston	625	3,000
Rest of System	-700	3,000
Valley	500	1,500
West	-500	3,000

Meeting the 0.1 LOLE standard is generally only expected for individual zones. In a multi-zone area, reaching 0.1 LOLE across the entire aggregated area would require meeting an even more stringent standard in each individual zone. The aggregated area measures LOLE when any one or more regions sheds firm load. Because load shed can occur in different days in different zones, all zones would need to be more reliable than 0.1 LOLE in order for the aggregate to also be at 0.1 LOLE. Notwithstanding this concession, recognition of transmission constraints will likely require higher reserve margins than historically identified to meet 0.1 LOLE in individual ERCOT zones. A more detailed representation of internal transmission constraints will be required to fully quantify the total impact to reliability planning. This will likely entail both more transmission dynamics being captured in the SERVM simulations as well as creation of thousands of distinct load and dispatch scenarios from SERVM to be analyzed in higher-resolution transmission planning tools.

KEY MODEL INPUTS AND PARAMETERS

A. MODELING FRAMEWORK

The study was performed using the Strategic Energy & Risk Valuation Model (SERVM). Like other reliability models, SERVM probabilistically evaluates the reliability implications of any given reserve margin. It does so by simulating generation availability, load profiles, load uncertainty, inter-regional transmission availability, and other factors. SERVM ultimately generates standard reliability metrics such as loss-of-load expectation (LOLE), loss-of-load hours (LOLH), and expected unserved energy (EUE). Unlike other reliability modeling packages, however, SERVM simulates economic outcomes, including hourly generation dispatch, ancillary services, and price formation under both normal conditions and emergency operating procedures.

The multi-area economic and reliability simulations in SERVM include an hourly chronological economic dispatch that is subject to inter-regional transmission constraints. Each generation unit is modeled individually, characterized by its economic and physical characteristics. Planned outages are scheduled in off-peak seasons, consistent with standard practices, while unplanned outages and derates occur probabilistically using historical distributions of time between failures and time to repair. Load, hydro, wind, and solar conditions are modeled based on profiles consistent with individual historical weather years. Dispatch limitations and limitations on annual energy output are imposed on certain types of resources such as demand response, hydro generation, and seasonally mothballed units.

The model implements a week-ahead and then multi-hour-ahead unit commitment algorithm considering the outlook for weather and planned generation outages. In the operating day, the model runs an hourly economic dispatch of baseload, intermediate, and peaking resources, including an optimization of transmission-constrained inter-regional power flows to minimize total costs. During most hours, hourly prices reflect marginal production costs, with higher prices being realized when import constraints are binding. During emergency and other peaking conditions, SERVM simulates scarcity prices that exceed generators' marginal production costs.

To examine a full range of potential reliability outcomes, we implement a Monte Carlo analysis over many scenarios (or "iterations") with varying demand and supply conditions. Because reliability events occur only when system conditions reflect unusually high loads or limited supply, these simulations must capture wide distributions of possible weather, load growth, and generation performance scenarios. This study incorporates 42 weather years, 3 to 5 levels of economic load forecast error (dependent on the study year),[1] and 25 draws of generating unit performance for a total of 5,250 iterations for each simulated case. Each individual iteration simulates 8,760 hours for the years 2023 and 2026.

To properly capture the magnitude and impact of reliability conditions during extreme events, a critical aspect of this modeling effort is the correct economic and operational characterization of emergency procedures. For this reason, SERVM simulates a range of emergency procedures, accounting for energy and call-hour limitations, dispatch prices, operating reserve depletion, dispatch of economic and emergency demand-response resources, and administrative scarcity pricing.[2]

B. STUDY YEARS

The zonal reliability study analyzed the expected conditions and resources in 2023 and 2026.

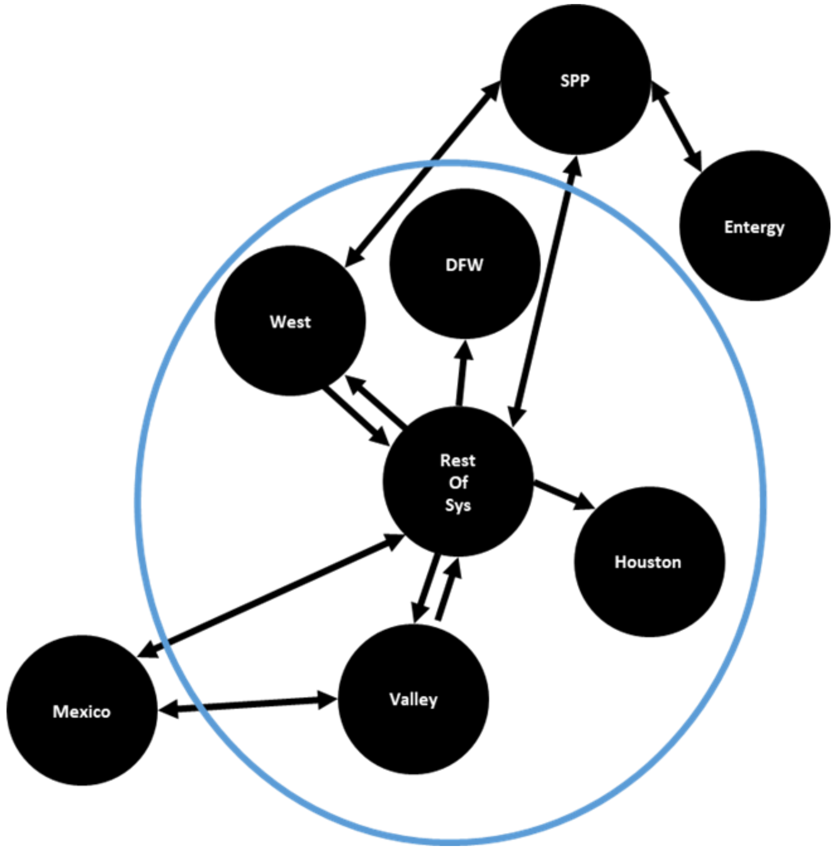
C. STUDY TOPOLOGY

Prior SERVM studies for the ERCOT region have assumed full deliverability of all generation within ERCOT. For this study, loads and generation were modeled within five distinct zones with import and export constraints between zones as shown in Figure 1. Neighboring electric systems - Entergy, SPP, and Mexico – were also modeled.

[1] The five discrete levels of load forecast error we model are equal to 0%, +/−2%, and +/−4% above and below the ERCOT load forecast (+/-4% were not used for the 2023 study year).

[2] Similar to other reliability modeling exercises, our study is focused on resource adequacy as defined by having sufficient resources to meet peak summer load. As such, we have not attempted to model other types of outage or reliability issues such as transmission and distribution outages, common mode failures related to winter weather extremes, or any potential issues related to gas pipeline constraints or delivery problems.

Figure 1. Study Topology



D. COMPONENTS OF SUPPLY AND DEMAND

Resource capacities as modeled within SERVM are presented in Table 1 and Table 3. Load and resource accounting for each zone for the Base Case in 2023 and 2026 is based on ERCOT's conventions in the May 2022 Capacity, Demand and Reserves (CDR) Report, as summarized in Table 2 and Table 4.[3] The fleet summary developed by ERCOT staff for the CDR Report was the most recent data available when this study was developed. Firm peak load is reduced for incremental rooftop photovoltaic (PV) forecast, non-controllable load resources (LRs), 10-minute and 30-minute emergency response service (ERS), and Transmission/ Distribution Service Providers (TDSP) energy efficiency and load management.

[3] https://www.ercot.com/gridinfo/resource

Table 1. Resource Capacities Modeled Within SERVM for 2023

Unit Category	Aggregate	Dallas	Houston	Rest Of System	Valley	West
4CP	900	83	150	492	5	169
BIOMASS	163	20	0	143	0	0
COAL	13,568	0	2,514	11,054	0	0
ERS	925	137	189	385	55	160
GAS-CC	31,132	0	4,818	21,959	1,190	3,165
GAS-GT	6,074	80	2,334	2,352	46	1,262
GAS-IC	922	226	0	280	225	190
GAS-ST	10,717	3,359	2,659	3,674	0	1,025
HYDRO	475	3	0	294	26	151
LRs	1,591	35	418	753	2	383
NUCLEAR	4,973	0	0	4,973	0	0
PBPC	200	50	42	77	6	24
PRD	1,500	138	250	821	9	282
PUNS	4,262	0	3,422	840	0	0
Reserve Shed	2,800	54	472	1,394	50	830
SOLAR	25,565	277	1,343	13,187	319	10,439
STORAGE	6,868	391	30	3,156	684	2,607
TDSP	307	70	133	69	4	30
WIND-C	5,439	0	0	2,995	2,445	0
WIND-O	29,024	0	0	3,853	1,451	23,720
WIND-P	5,054	0	0	0	0	5,054

Table 2. Supply and Demand Summary for 2023 Study Year

	Aggregate	DFW	Houston	Rest of System	Valley	West
Peak Load (MW)	**79,010**	**19,933**	**16,752**	**30,264**	**2,399**	**9,662**
Load Reduction (MW)	**2,823**	**242**	**740**	**1,207**	**61**	**573**
LRs serving RRS (MW)	1,591	35	418	753	2	383
10-Minute ERS (MW)	35	3	3	28	0	1
30-Minute ERS (MW)	890	135	185	356	55	159
TDSP Curtailment Programs (MW)	307	70	133	69	4	30
Supply (MW)	**104,263**	**3,912**	**16,834**	**59,216**	**3,639**	**20,662**
Conventional Generation (MW)	67,738	3,685	12,324	44,435	1,461	5,642
Hydro (MW)	475	3	0	294	26	151
Wind (MW)	10,421	0	0	2,478	1,684	6,260
Solar (MW)	20,708	224	1,088	10,681	259	8,456
Storage (MW)	6,666	391	30	2,955	684	2,607
PUNs (MW)	4,262	0	3,422	840	0	0
Capacity of DC Ties (MW)	850	0	0	488	209	153
Reserve Margin (%)	36.9%	-80.1%	5.1%	103.8%	55.6%	127.3%

*Capacity credits, aligned with the CDR, assigned in the reserve margin calculations: Wind-C: 57%, Wind-O: 20%, Wind-P: 30%, Solar: 81%, Hydro: 83%, and Storage: 0%.

Note: Energy Efficiency Programs are already removed from the modeled peak load and are not represented in the modeled load reduction programs (ERCOT Aggregate = 3,262 MW in 2023 Study Year).

Table 3. Resource Capacities Modeled Within SERVM for 2026

Unit Category	Aggregate	Dallas	Houston	Rest Of System	Valley	West
4CP	900	83	150	492	5	169
BIOMASS	163	20	0	143	0	0
COAL	13,568	0	2,514	11,054	0	0
ERS	852	127	174	354	50	148
GAS-CC	31,132	0	4,818	21,959	1,190	3,165
GAS-GT	6,085	80	2,345	2,352	46	1,262
GAS-IC	922	226	0	280	225	190
GAS-ST	10,717	3,359	2,659	3,674	0	1,025
HYDRO	475	3	0	294	26	151
LRs	1,591	35	418	753	2	383
NUCLEAR	4,973	0	0	4,973	0	0
PBPC	200	50	42	77	6	24
PRD	1,500	138	250	821	9	282
PUNS	4,262	0	3,413	840	0	0
Reserve Shed	2,800	54	472	1,394	50	830
SOLAR	39,299	522	1,404	21,035	699	15,638
STORAGE	7,832	391	30	3,990	684	2,737
TDSP	307	70	133	69	4	30
WIND-C	5,900	0	0	2,995	2,905	0
WIND-O	30,150	0	0	4,260	1,451	24,439
WIND-P	4,903	0	0	0	0	4,903

Table 4. Supply and Demand Summary for 2026 Study Year

	Aggregate	DFW	Houston	Rest of System	Valley	West
Peak Load (MW)	**82,615**	**20,832**	**17,655**	**31,568**	**2,765**	**9,795**
Load Reduction (MW)	**2,750**	**231**	**725**	**1,176**	**57**	**561**
LRs serving RRS (MW)	1,591	35	418	753	2	383
10-Minute ERS (MW)	32	2	3	26	0	1
30-Minute ERS (MW)	820	125	172	328	50	147
TDSP Curtailment Programs (MW)	307	70	133	69	4	30
Supply (MW)	**115,874**	**4,111**	**16,885**	**65,655**	**4,209**	**25,014**
Conventional Generation (MW)	67,558	3,685	12,335	44,435	1,461	5,642
Hydro (MW)	475	3	0	294	26	151
Wind (MW)	10,864	0	0	2,559	1,946	6,359
Solar (MW)	31,865	423	1,137	17,039	566	12,700
Storage (MW)	7,832	391	30	3,990	684	2,737
PUNs (MW)	4,262	0	3,413	840	0	9
Capacity of DC Ties (MW)	850	0	0	488	209	153
Reserve Margin (%)	45.1%	-80.0%	-0.3%	116.0%	55.4%	170.9%

* Capacity credits, aligned with the CDR, assigned in the reserve margin calculations: Wind-C: 57%, Wind-O: 20%, Wind-P: 30%, Solar: 81%, Hydro: 83%, and Storage: 0%.

Note: Energy Efficiency Programs are already removed from the modeled peak load and are not represented in the modeled load reduction programs (ERCOT Aggregate = 4,517 MW in 2026 Study Year).

On the demand side, this study started with ERCOT's zonal hourly load shapes under many possible weather patterns and peak load forecast for 2023. Astrapé simulated each of 42 weather years, from 1980 through 2021 (with corresponding wind and solar conditions from the same years). When calculating expected values, an equal probability for each year's weather was assumed.[4]

E. DEMAND SHAPES AND WEATHER UNCERTAINTY MODELING

We represented weather uncertainty in the projected ERCOT 2023 and 2026 peak loads by modeling 42 load forecasts based on 42 historical weather patterns from 1980-2021. Figure 2 shows the variability in summer and winter peak load across the 42 weather years simulated for this study. The most severe summer peak is 6.2% above the normal weather summer peak while the most severe winter peak is 26.9% above the normal weather winter peak.

[4] Applying equal probabilities is reasonable given that so many years can be taken to be fairly representative of the underlying distribution, assuming there is not a trend in the average weather or in the variability of weather.

Figure 2. Seasonal Peak Load Variance by Weather Year

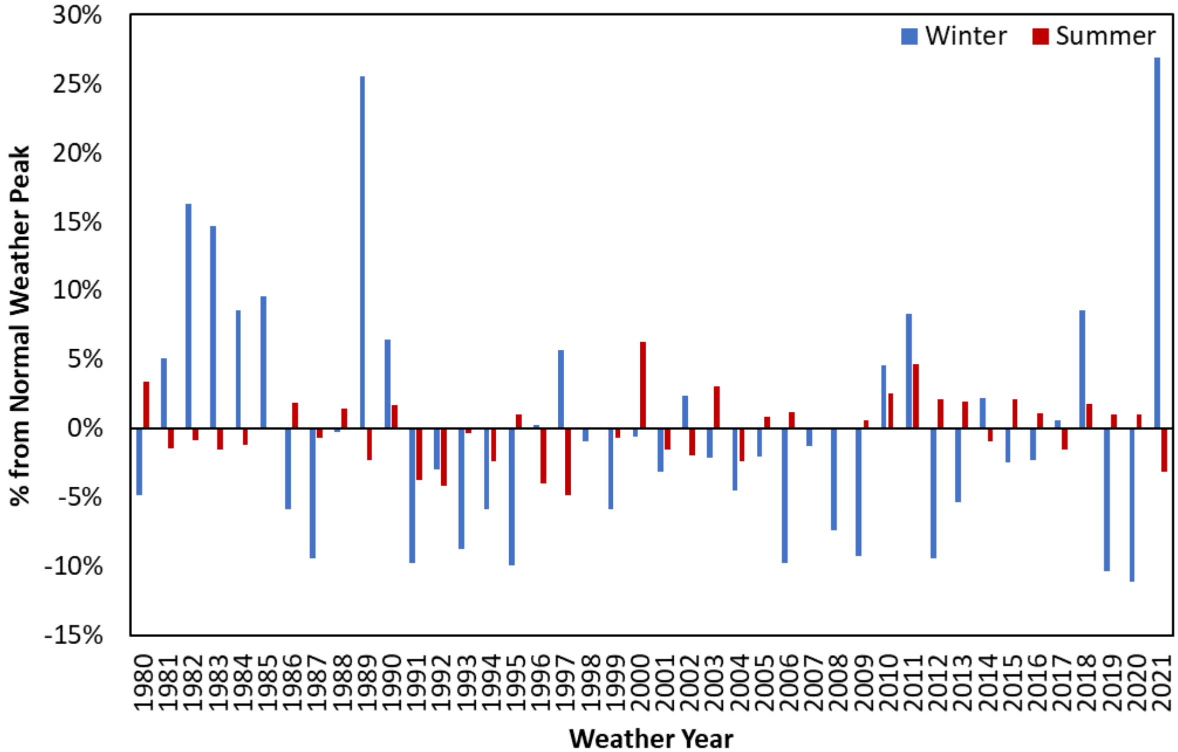


Table 5 shows the summer load diversity between ERCOT zones and the external neighbors. When the system, which includes all regions in the study, is at its summer peak, the individual regions are approximately 2-5% below their non-coincidental peak on average over the 42-year period.

Table 5. Zonal Diversity - Summer

	Non-Coincident Peak (MW)	System Coincident Peak (MW)	ERCOT System Peak (MW)	Load Diversity at ERCOT System Peak (% Below System Coincident Peak)	Load Diversity (% Below System Non-Coincident Peak)	
					System Below Non-Coincident	ERCOT System Below Non-Coincident
DFW	19,912	19,344	19,745	-2.1%	2.9%	0.8%
Houston	16,977	16,382	16,749	-2.2%	3.6%	1.4%
Rest Of System	30,000	29,298	29,951	-2.2%	2.4%	0.2%
Valley	2,602	2,496	2,548	-2.1%	4.2%	2.1%
West	9,420	9,236	9,332	-1.0%	2.0%	0.9%
Mexico	13,380	12,979	13,176	-1.5%	3.1%	1.5%
Entergy	33,852	33,019	31,005	6.1%	2.5%	9.2%
SPP	53,112	51,912	47,545	8.4%	2.3%	11.7%
ERCOT System	78,325	76,757	78,325	-2.0%	2.0%	0.0%
System	174,667	174,667	170,051	2.6%	0.0%	2.7%

Table 6 shows the winter load diversity between ERCOT zones and the external neighbors. When the system, which includes all regions in the study, is at its winter peak, the individual regions are approximately 0-11% below their non-coincidental peak on average over the 42-year period.

Table 6. Zonal Diversity - Winter

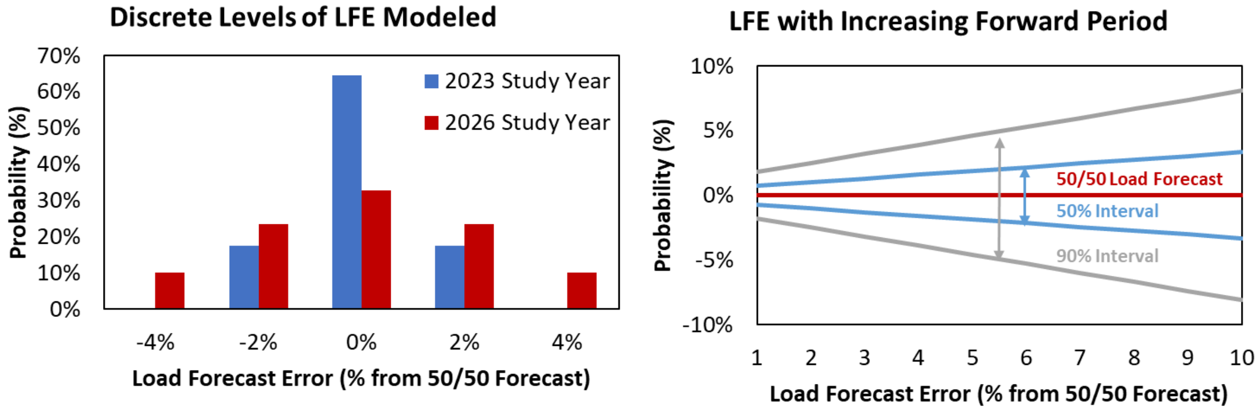
	Non-Coincident Peak (MW)	System Coincident Peak (MW)	ERCOT System Peak (MW)	Load Diversity at ERCOT System Peak (% Below System Coincident Peak)	Load Diversity (% Below System Non-Coincident Peak)	
					System Below Non-Coincident	ERCOT System Below Non-Coincident
DFW	17,983	17,455	17,773	-1.8%	3.0%	1.2%
Houston	13,078	12,668	12,806	-1.1%	3.2%	2.1%
Rest Of System	26,837	26,011	26,670	-2.5%	3.2%	0.6%
Valley	2,526	2,282	2,344	-2.7%	10.7%	7.8%
West	8,496	8,382	8,451	-0.8%	1.4%	0.5%
Mexico	11,455	11,300	11,394	-0.8%	1.4%	0.5%
Entergy	30,674	29,260	26,986	7.8%	4.8%	13.7%
SPP	42,453	40,674	38,918	4.3%	4.4%	9.1%
ERCOT System	68,044	66,798	68,044	-1.9%	1.9%	0.0%
System	148,033	148,033	145,342	1.8%	0.0%	1.9%

F. NON-WEATHER DEMAND FORECAST UNCERTAINTY AND FORWARD PERIOD

The load forecast errors were updated to reflect a 1 and 4 year ahead look that reflects that load may grow faster or slower than expected. As shown in the right chart of Figure 3, we assume that non-weather load forecast error (LFE) is normally distributed with a standard deviation of 0.43% on a 1-year forward basis, increasing by 0.66% with each additional forward year.[5] The distribution included no bias or asymmetry in non-weather LFEs, unlike the weather-driven LFE in ERCOT, which has more upside than downside uncertainty. The left-hand chart of Figure 3 shows the three or five discrete levels of LFE we modeled, equal to 0%, +/−2%, and +/-4% above and below the forecast. The largest errors are the least likely, consistent with a normal distribution.

[5] This assumed LFE is a standard assumption that we developed in lieu of any ERCOT-specific analysis, which would require either a longer history of load forecasts in ERCOT or a new analysis developed out of ERCOT's peak load forecast, neither of which are currently available.

Figure 3. Non-Weather Load Forecast Error



G. EXTERNAL REGION MODELING

The neighbors - Entergy, SPP, and Mexico - were updated to reflect 2023 and 2026 load forecasts and resources. External regions' peak load and load shapes were independently developed based on publicly available peak load projections, historical hourly weather profiles, and historical hourly load data.

H. GENERATION RESOURCES

The economic, availability, ancillary service capability, and dispatch characteristics of all generation units in the ERCOT fleet are modeled, using unit ratings and online status consistent with ERCOT's May 2022 CDR report.

1. CONVENTIONAL GENERATION OUTAGES

A major component of reliability analyses is modeling the availability of supply resources after considering maintenance and forced outages. We model forced and maintenance outages of conventional generation units stochastically. Partial and full forced outages occur probabilistically based on distributions accounting for time-to-fail, time-to-repair, startup failure rates, and partial outage derate percentages. Maintenance outages also occur stochastically, but SERVM accommodates maintenance outages with some flexibility to schedule maintenance during off-peak hours. Planned outages are differentiated from maintenance outages and are scheduled in advance of each hourly simulation. Consistent with market operations, the planned outages occur during low demand periods in the spring and fall, such that the highest coincident planned outages occur in the lowest load days. This outage modeling approach allows SERVM to recognize some system-wide scheduling flexibility while also capturing the potential for severe scarcity caused by a number of coincident unplanned outages.

We develop distributions of outage parameters for time-to-fail, time-to-repair, partial outage derate percentages, startup probabilities, and startup time-to-repair from historical Generation Availability Data System (GADS) data for individual units in ERCOT's fleet, supplemented by asset class average outage rates provided by ERCOT where unit-specific data were unavailable. Table 7 summarizes fleet-wide and asset-class outage rates, including both partial and forced outages.

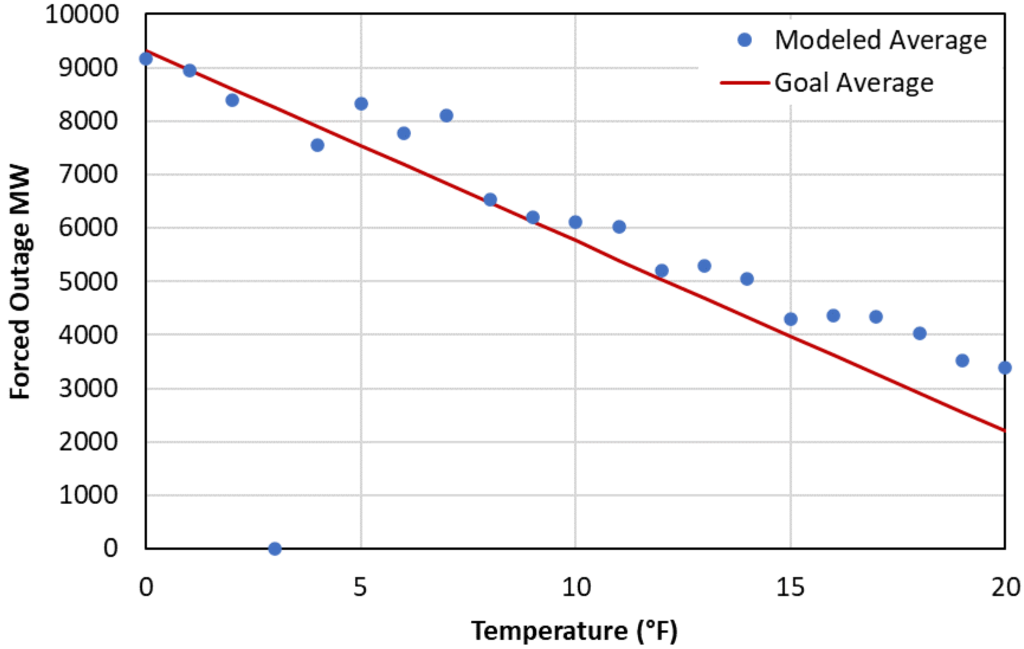
Table 7. Equivalent Forced Outage Rates by Asset Class

Unit Type	EFOR (%)
Gas	10.1
Biomass	4.9
Coal	10.2
Nuclear	0.3
Storage	5.0
Fleet Weighted Average	**8.92**

Additional forced outage probabilities were modeled for temperatures below 20°F, as shown in Figure 4. Forced outages from 2018-2021 as a function of temperature were analyzed while excluding winter storm Uri. A trend was added to the graph below 20 degrees and extrapolated to 0 degrees (Goal Average series below).[6] A linear probability was assigned with an hourly incremental forced outage probability of 1.07% at 0°F down to 0% at 20°F leading to an average of ~9,000 total MW being forced offline at 0°F. The impacts of the new weatherization requirements are not being considered in the temperature outage correlation modeling.

[6] The extrapolated value at 0°F was not as extreme as the 2011 outages (14.7 GW forced offline when system temperatures were roughly 14°F (see FERC link). Modeling this way reflected improvement from both 2011 and 2021 but also reflected an increased risk from what has been modeled in previous studies. https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfromFebruary2011Report.pdf

Figure 4. Cold Weather Forced Outage Modeling[7]

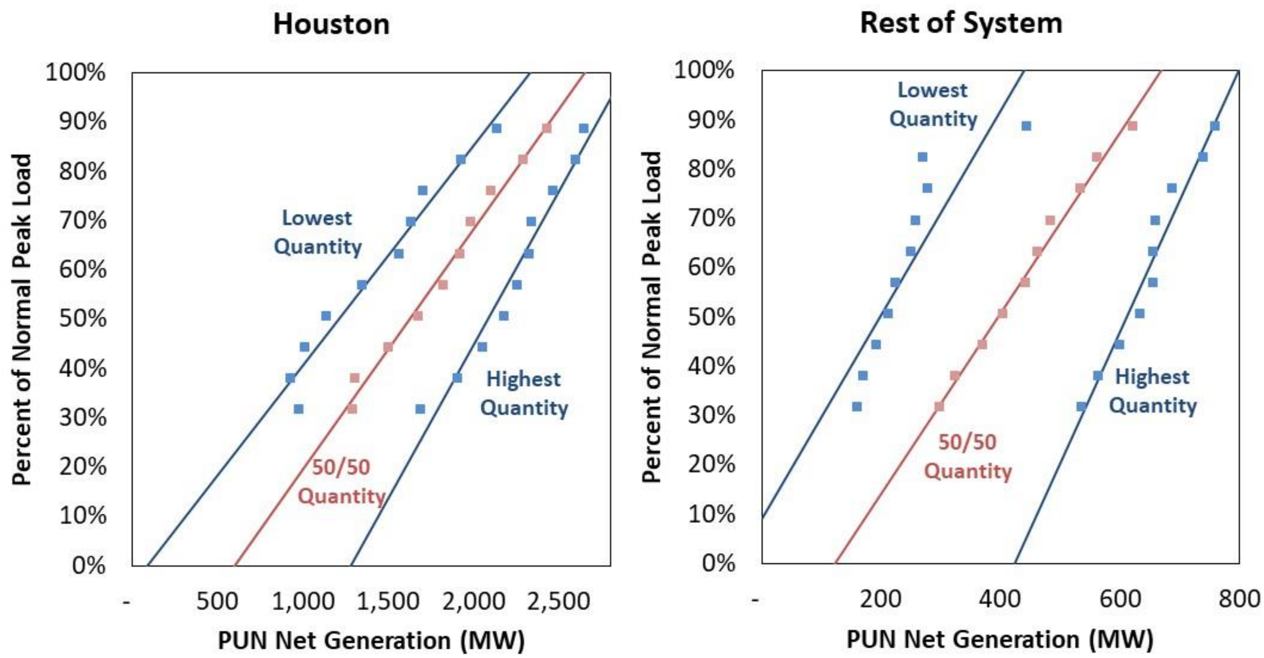


2. PRIVATE USE NETWORKS

We represent generation from Private Use Networks (PUNs) in ERCOT on a net generation basis by zone, where the net output increases with the system portion of peak load consistent with historical data and as summarized in Figure 5. The Houston PUNs are modeled with 3,412 MW capacity, Rest of System PUNs are modeled with 840 MW capacity, and West PUNs are modeled with 9 MW of capacity. At any given load, the realized net PUN generation has a probabilistic quantity, with 10 different possible quantities of net generation within each of 10 different bands of system load.[8] Each of the 10 possible quantities has an equal 10% chance of materializing, although the figure reports only the lowest, median, and highest possible quantity. The probabilistic net PUN supply curve was developed based on aggregate hourly historical net output data within each range of peak load percentage. During scarcity conditions with load at or above 88% of normal peak load, PUN output produces at least 2,135 MW in Houston and 445 MW in Rest of System of net generation with an average of 2,430 MW and 621 MW respectively.

[7] There were no temperature points between 3-4°F in the average temperature profile used in the SERVM simulations.
[8] Hourly net PUN output data by zone gathered from ERCOT.

Figure 5. PUN Net Generation



3. INTERMITTENT WIND AND SOLAR

We modeled a total quantity of intermittent wind and solar photovoltaic resources that reflects what ERCOT reported in the May 2022 CDR Report. This included 39,517 MW nameplate capacity of wind and 25,565 MW nameplate of solar in 2023 and 40,952 MW nameplate capacity of wind and 39,339 MW nameplate of solar in 2026, with intermittent output based on hourly generation profiles that were specific to each weather year.

We developed our system-wide hourly wind profiles by aggregating 42 years of synthesized hourly wind shapes for each location of individual units across the system wind shapes over 1980 to 2021, as provided by ERCOT staff.[9] Figure 6 plots the average wind output by season and time of day, showing the highest output overnight and in spring months with the lowest output in mid-day and in summer months. The overall capacity factor for wind resources was 39.3%.

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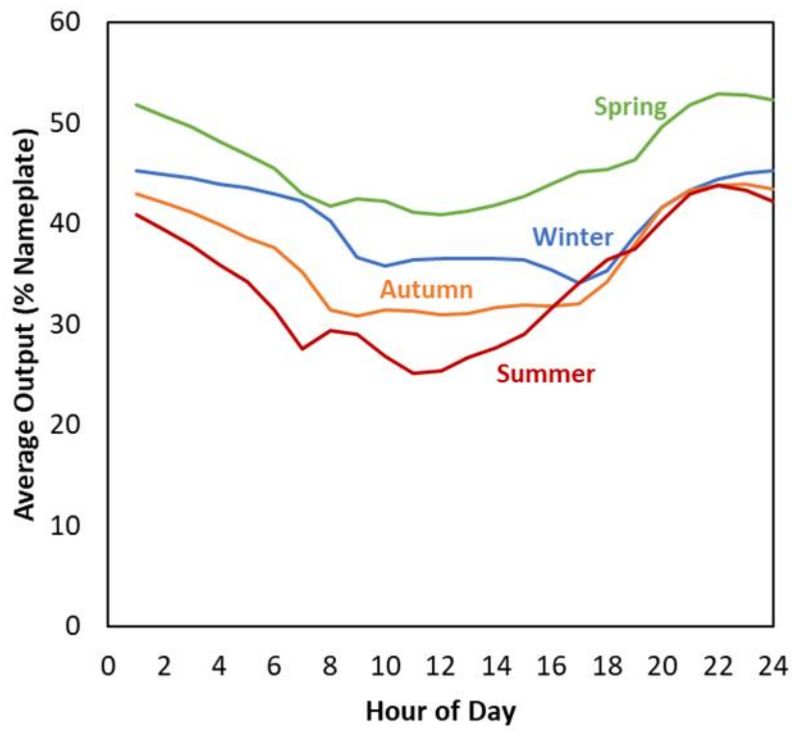
[9] We aggregated location-specific output profiles for all units, including traditional and coastal units. ERCOT obtained the original wind profiles from UL (formerly AWS Truepower).

Figure 6. Average Wind Output by Month and Time of Day



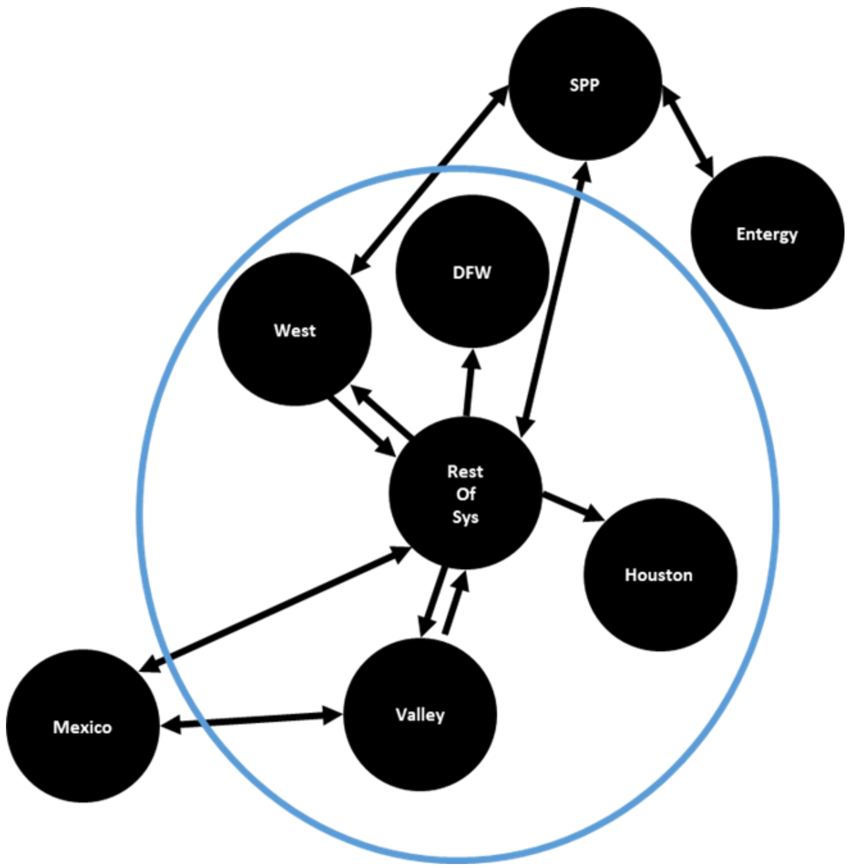
We similarly model hourly solar PV output based on hourly output profiles that are specific to each weather year, as aggregated from county-specific synthesized output profiles over years 1980 to 2021.[10] In aggregate, solar resources had a capacity factor of 26.0% across all years.

[10] Individual county and site-specific output profiles for 1980-2021 were provided by ERCOT, obtained through UL (formerly AWS Truepower).

RESULTS

ERCOT was treated as a copper sheet for the base case for this study; that is, with no transmission constraints applied. The base reliability was determined, and then coal capacity was retired until the system reached 0.1 LOLE for both the 2023 and 2026 study years. The copper sheet transmission group was then replaced with a more constrained group. The transmission limits used in the constrained group are shown in Figure 7.

Figure 7. Constrained Group Transmission Limits



The results of the copper sheet with coal retired to 0.1 LOLE and the constrained transmission limits are presented in Table 8. ERCOT Aggregate measures LOLE when any one or more regions sheds firm load. In the constrained scenario, the Aggregate LOLE is not simply the sum of the LOLE in all ERCOT zones because load shed can occur in different days in different zones resulting in an aggregate LOLE greater than 0.1.

Table 8. Base Case and Transmission Constrained Case Results

Transmission Group	Region	LOLE (events/year) 2023 Study Year	LOLE (events/year) 2026 Study Year
Copper Sheet	Aggregate	0.102	0.097
	Dallas	0.102	0.093
	Houston	0.102	0.097
	Rest Of System	0.098	0.097
	Valley	0.101	0.095
	West	0.101	0.096
Constrained	Aggregate	2.033	1.625
	Dallas	0.284	0.321
	Houston	0.172	0.304
	Rest Of System	0.203	0.170
	Valley	1.921	1.288
	West	0.204	0.172

Regions that have more than 100% reserve margin, such as Rest of System and West, have worsening LOLE from the copper sheet to the constrained case. The worsening LOLE is driven by the import constraints. When Rest of System is having events, and regions such as Valley are not having events, Valley is curtailing large amounts of renewable capacity due to its export constraint limits. For additional sensitivities performed as part of a separate multi-zone reliability study, when these limits are relaxed, the LOLE remained the same for the copper sheet and the constrained cases.[11]

The constraint imposed on the simulations was a single import/export constraint that reflects a specific non-coincident peak load condition, so these results do not represent reality. In reality, these constraints are contingent on generator dispatch patterns, load levels, etc. As an example, from the 2023 study year, typical conditions in the Valley region during EUE events in the constrained condition are shown in Table 9 for winter and summer.

Table 9. Details about Valley in 2023 Study Year when EUE Events are Greater Than 500 MWh

	Winter	Summer
Load (MW)	2,460	2,486
Net Load (MW)	2,038	2,026
EUE (MWh)	760	647
Online Steam (MW)	327	174
Online CT (MW)	266	255
Renewables (MW)	401	415
Forced Outages (MW)	824	883
Purchases (MWh)	857	1,007
Interruptible Dispatched (MW)	97	109

[11] The study is being conducted for the North American Electric Reliability Corporation (NERC) as part of its 2022 Long Term Reliability Assessment. Results of the multi-zone reliability study will be included in a NERC report expected to be released in mid-2023.

The monthly LOLE results for 2023 and 2026 are shown in Table 10 and Table 11, respectively.

Table 10. Monthly LOLE Results for 2023 Study Year

	Region	Annual	1	2	3	4	5	6	7	8	9	10	11	12
Copper Sheet	Aggregate	0.102	0.01	0.05	-	-	-	-	-	0.00	-	-	-	0.04
	Dallas	0.102	0.01	0.05	-	-	-	-	-	0.00	-	-	-	0.04
	Houston	0.101	0.01	0.05	-	-	-	-	-	0.00	-	-	-	0.04
	Rest of System	0.129	-	0.00	-	-	-	-	0.04	0.08	0.01	-	-	-
	Valley	0.092	-	-	-	-	-	0.00	0.05	0.02	0.02	-	-	-
	West	0.284	0.04	0.09	-	-	-	0.00	0.01	0.07	0.00	-	-	0.08
Constrained	Aggregate	2.033	0.53	0.16	0.04	0.08	0.04	0.07	0.07	0.16	0.12	0.16	0.20	0.40
	Dallas	0.284	0.04	0.09	-	-	-	0.00	0.01	0.07	0.00	-	-	0.08
	Houston	0.172	0.01	0.04	-	-	-	0.00	0.00	0.06	0.01	-	-	0.05
	Rest of System	0.203	0.03	0.05	-	-	-	0.00	0.00	0.05	0.00	-	-	0.07
	Valley	1.921	0.52	0.15	0.04	0.08	0.04	0.06	0.06	0.12	0.11	0.16	0.20	0.36
	West	0.204	0.03	0.06	-	-	-	0.00	0.00	0.05	0.00	-	-	0.07

Table 11. Monthly LOLE Results for 2026 Study Year

	Region	Annual	1	2	3	4	5	6	7	8	9	10	11	12
Copper Sheet	Aggregate	0.097	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
	Dallas	0.093	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
	Houston	0.097	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
	Rest of System	0.097	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
	Valley	0.095	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
	West	0.096	0.00	0.04	-	-	-	0.00	-	0.00	-	-	-	0.05
Constrained	Aggregate	1.625	0.18	0.09	0.02	0.01	0.06	0.11	0.09	0.25	0.15	0.11	0.17	0.38
	Dallas	0.321	0.02	0.06	-	-	-	0.00	0.03	0.08	0.05	-	-	0.08
	Houston	0.304	0.01	0.04	-	-	0.00	0.01	0.03	0.13	0.02	0.00	-	0.06
	Rest of System	0.170	0.01	0.05	-	-	-	-	-	0.03	0.00	-	-	0.07
	Valley	1.288	0.16	0.08	0.02	0.01	0.06	0.10	0.04	0.11	0.09	0.10	0.17	0.34
	West	0.172	0.01	0.05	-	-	-	-	0.00	0.03	0.00	-	-	0.07

From the constrained transmission limits, two sensitivities were completed to determine the sensitivity of perfect capacity and pipe size between the zones:

1. Perfect Capacity
    a. Perfect capacity was added to each zone iteratively with the objective of adding minimal net capacity in aggregate across ERCOT to achieve 0.1 LOLE in all zones
    b. Meeting this objective required reducing capacity in some zones
2. Transmission Capability

a. Transmission limits were bidirectionally relaxed on each internal ERCOT transmission tie iteratively with the objective of minimal net adjustments to transmission capability across all zonal ties to meet 0.1 in all zones

The 2023 results are shown graphically in Figure 8 with the addition/relaxation values defined in Table 12. ERCOT Aggregate measures LOLE when any one or more regions sheds firm load. In a constrained scenario, load shed can occur in different days in different zones resulting in an aggregate LOLE > 0.1.

Figure 8. 2023 Study Year Results[12]

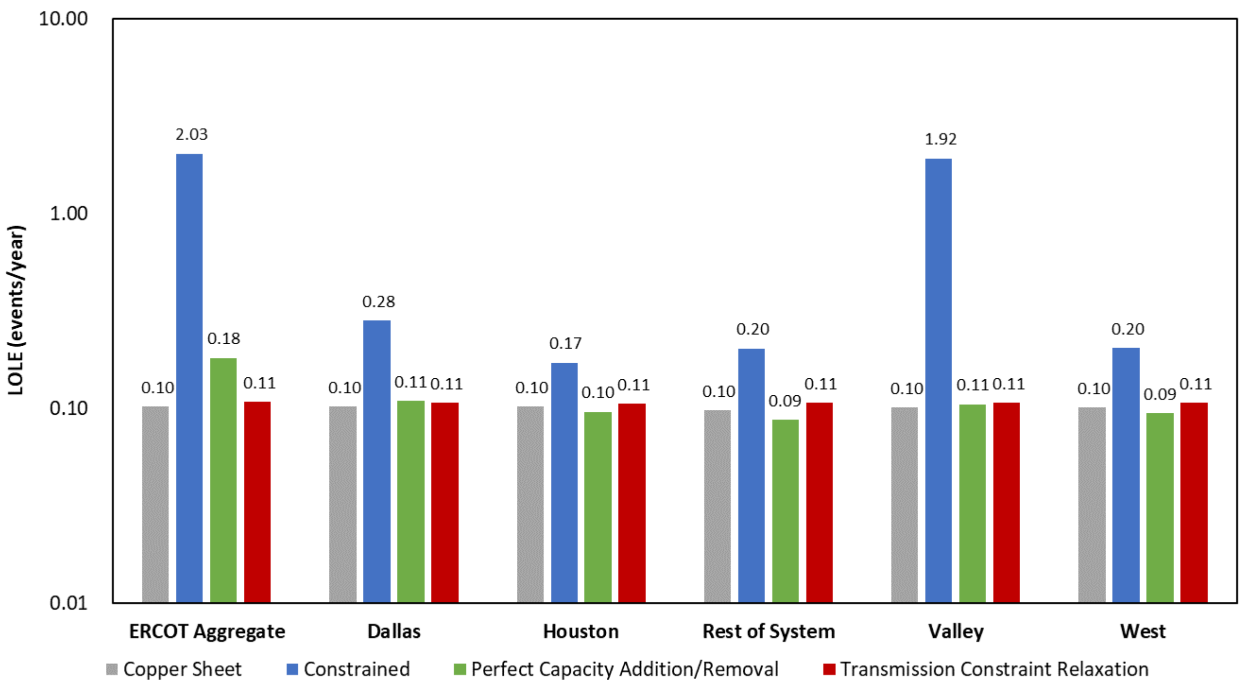


Table 12. 2023 Study Year Results

Region	Perfect Capacity Addition/Removal (MW)	Transmission Constraint Relaxation (MW)
Dallas	3,750	2,500
Houston	-150	2,500
Rest of System	-300	2,500
Valley	500	1,500
West	-300	2,500

Several zones in the initial setup had adequate capacity (Houston, Rest of System, and West). This is true even though they showed higher than 0.1 LOLE. Their reliability issues were driven by the process of sharing EUE across zones if a transmission constraint is not binding. So, the zones that had excess showed

[12] ERCOT Aggregate measures LOLE when any one or more regions sheds firm load. In a constrained scenario, load shed can occur in different days in different zones resulting in an aggregate LOLE > 0.1.

worse than target reliability because they supported neighboring zones even to the point of shedding load. Because these zones had adequate capacity initially, the most efficient method - or the method that required the fewest total MW to be added to the aggregate system - was to remove capacity from long zones and add capacity to short zones.

The 2026 results are shown graphically in Figure 9 with the capacity additions/removals and transmission relaxation values defined in Table 13. ERCOT Aggregate measures LOLE when any one or more regions sheds firm load. In a constrained scenario, load shed can occur in different days in different zones resulting in an aggregate LOLE > 0.1.

Figure 9. 2026 Study Year Results[13]

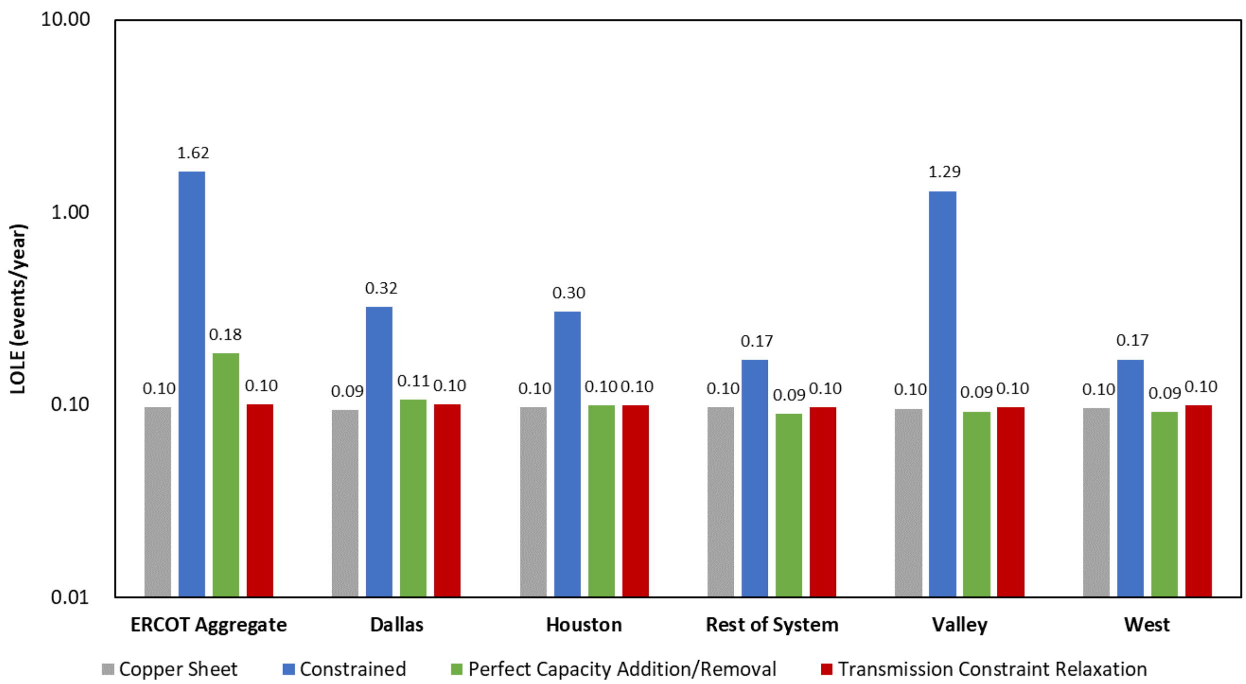


Table 13. 2026 Study Year Results

Region	Perfect Capacity Addition/Removal (MW)	Transmission Constraint Relaxation (MW)
Dallas	3,500	3,000
Houston	625	3,000
Rest of System	-700	3,000
Valley	500	1,500
West	-500	3,000

[13] ERCOT Aggregate measures LOLE when any one or more regions sheds firm load. In a constrained scenario, load shed can occur in different days in different zones resulting in an aggregate LOLE > 0.1.

CONCLUSION AND NEXT STEPS

While the transmission system in actual practice is much more dynamic than represented in this analysis, the input development was intended to capture realistic constraints between major areas within ERCOT during high load periods. The imposition of internal transmission constraints had significant implications for projected reliability within ERCOT. A more detailed representation of internal transmission constraints will be required to fully quantify the total impact to reliability planning. This will likely entail both more transmission dynamics being captured in the SERVM simulations as well as creation of thousands of distinct load and dispatch scenarios from SERVM to be analyzed in higher resolution transmission planning tools.

APPENDIX

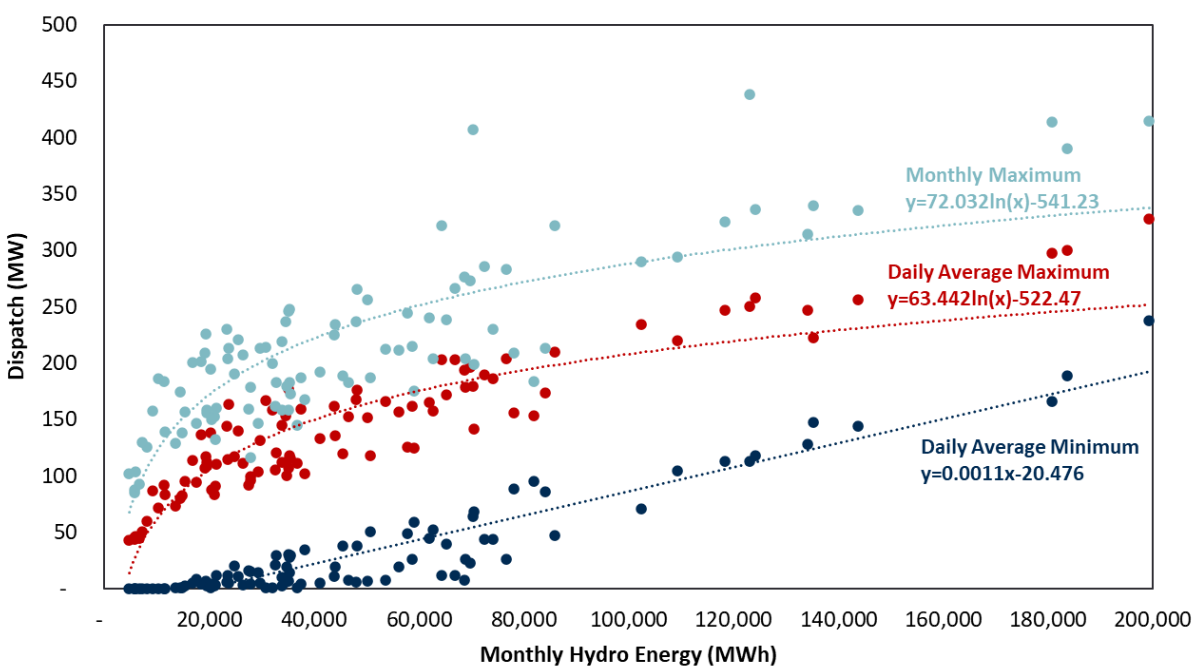
A. GENERATION RESOURCES

1. HYDROELECTRIC

We include 557.4 MW of hydroelectric resources, consistent with ERCOT's May 2022 CDR report. We characterize hydro resources using eight years of hourly data over 2012-2019 provided by ERCOT, and 42 years of monthly data over 1980-2021 from Form EIA-923.[14] For each month, SERVM uses four parameters for modeling hydro resources, as summarized in Figure A1: (1) monthly total energy output, (2) monthly maximum output, (3) daily maximum output, and (4) daily minimum output, as estimated from historical data.

When developing hydro output profiles, SERVM will first schedule output up to the monthly maximum output into the peak hours but will schedule some output across all hours based on historically observed output during off-peak periods up to the total monthly output. During emergencies, SERVM can schedule up to 49.25 MW in drought conditions and 116.15 MW for all other months.

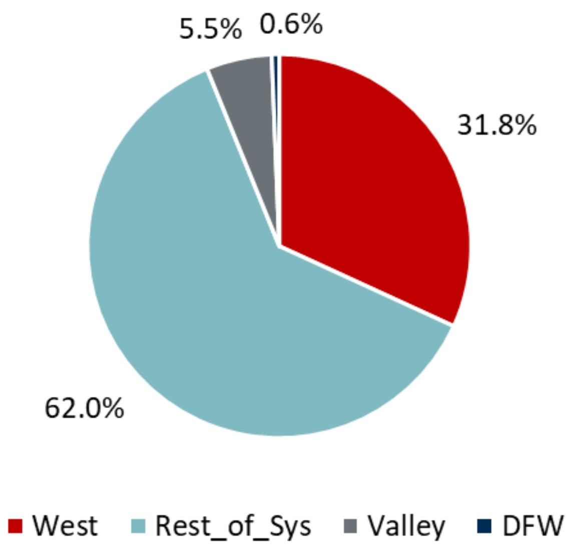
Figure A1. Historical Hydro Energy Relationships



The overall relationships were split up between the West, Rest of System, Valley, and Dallas zones based upon the capacity breakdown provided in ERCOT's May 2022 CDR Report, as shown in Figure A2.

[14] https://www.eia.gov/electricity/data/eia923/

Figure A2. Hydro Capacity Breakdown by Zone



2. FUEL PRICES

We used natural gas future quotes for 2023 and the 2022 Annual Energy Outlook Reference case for our gas price future inputs for 2026.[15] The average fuel prices used in the study are presented in Table A1.

Table A1. ERCOT Fuel Forecasts

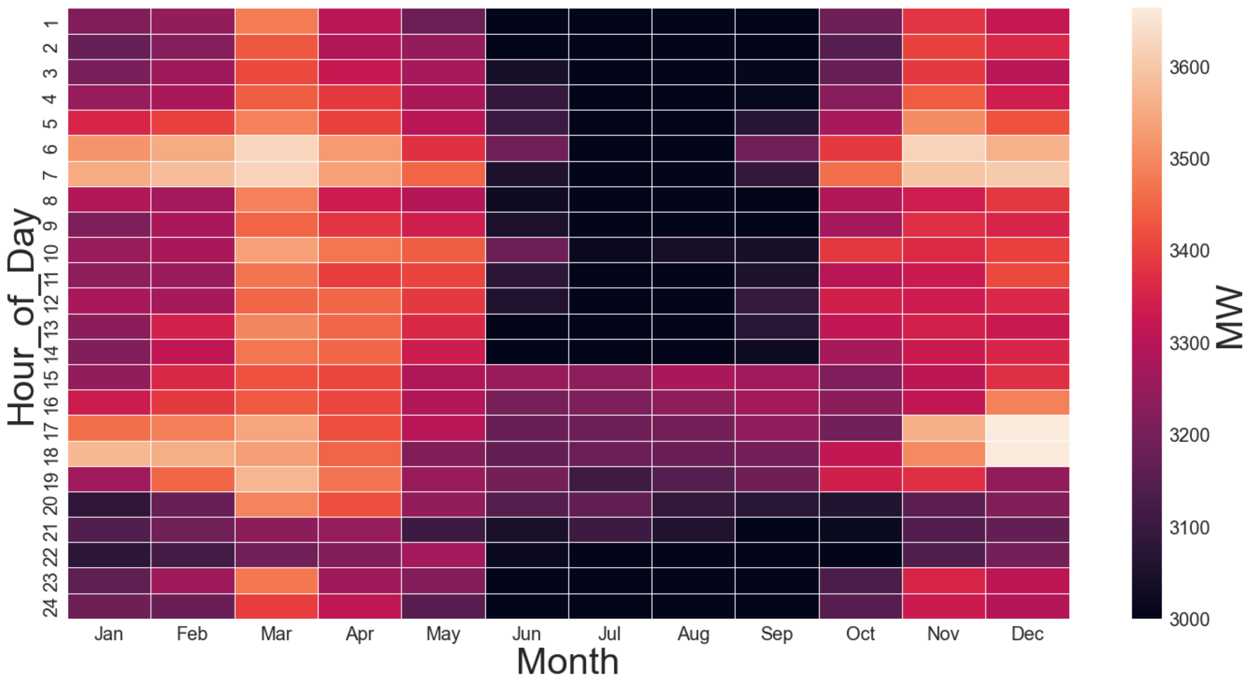
	Coal Fuel Price ($/MMBtu)	Gas Fuel Price ($/MMBtu)	Diesel Fuel Price ($/MMBtu)
2023	2.51	5.69	10.83
2026	2.65	3.33	15.23

B. ANCILLARY SERVICE MODELING

Ancillary services are necessary to maintain the reliability of the ERCOT System. Ancillary services are procured to ensure sufficient resource capacity is online or able to be brought online in a timely manner to balance the variability that cannot be covered by the 5-minute energy market. The four types of Ancillary Services in ERCOT currently are: regulation up service, regulation down service, responsive reserve service, and non-spinning reserve service. ERCOT typically maintains a minimum of 3,000 - 4,000 MW of online upward reserves in order to protect reliability in the event of a disturbance or to provide the necessary flexibility to follow potentially volatile net load patterns. A heatmap of the monthly and hourly online upward reserve minimums is shown in Figure A3. The requirements were split up within the zones based on values or percentages provided by ERCOT.

[15] https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html

Figure A3. Upward Reserve Requirements



SERVM maintains these online upward reserves when adequate resources are available. When resource availability declines during simulations, emergency operating procedures are activated in SERVM to deploy reserves and call emergency resources such as demand response. Emergency operating procedures are discussed in more detail in Section C.

C. SCARCITY PRICING AND DEMAND RESPONSE MODELING

Several types of demand response participate directly or indirectly in ERCOT's market, including Emergency Response Service (ERS), Load Resources, and Price Responsive Demand. These various resource types differ from each other in whether they are triggered by price-based or emergency actions, and restrictions on availability and call hours. Table A2 summarizes the resources, explaining how we modeled their characteristics and their assumed marginal costs when utilized, and how they were accounted for in the reserve margin.

Table A2. Summary of Demand Resource Characteristics and Modeling Approach

Resource Type	Quantity (MW)	Modeling Approach	Marginal Curtailment Cost	Adjustments to ERCOT Load Shape	Reserve Margin Accounting
TDSP Programs					
Energy Efficiency	3,262 in 2023 4,517 in 2026	Not explicitly modeled.	*n/a*	None	Load reduction
Load Management	307	Emergency trigger at EEA Level 1	$2,543	None	Load reduction
Emergency Response Service (ERS)					
30-Minute ERS	890 in 2023 820 in 2026	Emergency trigger at EEA Level 1	$1,721	None	Load reduction
10-Minute ERS	35 in 2023 32 in 2026	Emergency trigger at EEA Level 2	$2,543	None	Load reduction
Load Resources (LRs)					
Non-Controllable LRs	1,591	Economically dispatch for Responsive Reserve Service (most hours) or energy (few peak hours). Emergency deployment at EEA Level 2	$2,543	None	Load reduction
Controllable LRs		Currently no controllable LRs modeled in ERCOT	*n/a*	*n/a*	*n/a*
Voluntary Self-Curtailments					
4 CP Reductions	1,700	Load shapes grossed up for projected response and corresponding response modeled on the resource side	*n/a*	None	None; excluded from reported peak load
Price Responsive Demand	Variable	Load shapes explicitly grossed up for expected response. Economic self-curtailment modeled on resource side	$5,000 - $5,000/MWh	None	None; excluded from reported peak load

Sources and Notes:
Developed based on analyses of recent DR participation in each program and input and data from ERCOT staff.

Table A3 provides a summary of the modeled capacity breakdown by zone for the demand response resources.

Table A3. Modeled Demand Response Resource Capacity by Zone

Region	Demand Response Resource Capacity (MW)					
	ERS	**LRs**	**PBPC**	**PRD**	**4CP**	**TDSP**
Dallas	137	35	50	138	83	70
Houston	189	418	42	250	150	133
Rest Of System	385	753	77	821	492	69
Valley	55	2	6	9	5	4
West	160	383	24	282	169	30
Total	**925**	**1591**	**200**	**1500**	**900**	**307**

1. EMERGENCY RESPONSE SERVICE

Emergency response service (ERS) includes two types of products, 10-minute and 30-minute (weather sensitive and non-weather sensitive) ERS, with the quantity of each product available changing by time of day and season as shown in Table A4. The quantity of each product by time of day and season is proportional to the quantities most recently procured over the four seasons of year 2021 and 2022, with the 2023 and 2026 summer peak quantity assumptions provided by ERCOT.[16] Demand resources enrolled under ERS are dispatchable by ERCOT during emergencies but cannot be called outside their contracted hours and cannot be called for more than twenty-four hours total per season. The 2026 values scaled the values such that the June – September TP4 values match the total 2026 value provided.

[16] For total ERS procurement quantities by product type and season, see https://sa.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

Table A4. Assumed ERS Quantities Available in 2023

Contract Period	Quantity			
	10-Min NWS *(MW)*	30-Min NWS *(MW)*	30-Min WS *(MW)*	Total *(MW)*
June - September				
TP1: Weekdays HE 6 AM - 9 AM	47.1	991.3	-	1,038.4
TP2: Weekdays HE 10 AM - 1 PM	46.8	1,154.3	-	1,201.1
TP3: Weekdays HE 2 PM - 4 PM	38.3	1,040.1	41.8	1,120.2
TP4: Weekdays HE 5 PM - 7 PM	35.3	847.9	41.8	925.0
TP5: Weekdays HE 8 PM - 10 PM	42.4	985.7	-	1,028.2
TP6: Weekend and Holidays HE 6 AM - 9 AM	45.8	823.4	-	869.2
TP7: Weekend and Holidays HE 4 PM - 9 PM	40.8	818.8	-	859.6
TP8: All Other Hours	44.2	863.5	-	907.6
October - November				
TP1: Weekdays HE 6 AM - 9 AM	105.9	1,073.5	-	1,179.4
TP2: Weekdays HE 10 AM - 1 PM	95.1	1,032.4	-	1,127.5
TP3: Weekdays HE 2 PM - 4 PM	96.3	1,038.0	-	1,134.4
TP4: Weekdays HE 5 PM - 7 PM	107.6	1,109.1	-	1,216.8
TP5: Weekdays HE 8 PM - 10 PM	105.6	1,089.0	-	1,194.6
TP6: Weekend and Holidays HE 6 AM - 9 AM	103.2	956.8	-	1,060.0
TP7: Weekend and Holidays HE 4 PM - 9 PM	105.2	971.7	-	1,077.0
TP8: All Other Hours	57.6	900.1	-	957.8
December - March				
TP1: Weekdays HE 6 AM - 9 AM	97.8	994.7	5.5	1,098.0
TP2: Weekdays HE 10 AM - 1 PM	98.5	1,004.1	-	1,102.6
TP3: Weekdays HE 2 PM - 4 PM	99.8	1,010.9	-	1,110.7
TP4: Weekdays HE 5 PM - 7 PM	97.4	1,014.2	5.5	1,117.2
TP5: Weekdays HE 8 PM - 10 PM	96.7	996.5	5.5	1,098.8
TP6: Weekend and Holidays HE 6 AM - 9 AM	32.4	764.0	5.5	802.0
TP7: Weekend and Holidays HE 4 PM - 9 PM	33.8	802.6	-	836.4
TP8: All Other Hours	92.2	887.8	-	979.9
April - May				
TP1: Weekdays HE 6 AM - 9 AM	386.3	736.3	2.2	1,124.7
TP2: Weekdays HE 10 AM - 1 PM	345.7	771.5	-	1,117.3
TP3: Weekdays HE 2 PM - 4 PM	342.5	770.6	19.9	1,133.1
TP4: Weekdays HE 5 PM - 7 PM	375.4	752.5	27.7	1,155.6
TP5: Weekdays HE 8 PM - 10 PM	378.1	733.9	19.9	1,132.0
TP6: Weekend and Holidays HE 6 AM - 9 AM	332.5	530.6	-	863.1
TP7: Weekend and Holidays HE 4 PM - 9 PM	327.0	536.5	22.2	885.6
TP8: All Other Hours	336.5	643.3	-	979.9

Sources and Notes:

Total available ERS MW for 2023 June-Sept. TP4 provided by ERCOT staff.

ERS 10-min and 30-min MW for other contract periods scaled proportionally to the study year quantities based on availability in 2021-2022.

The ERS total capacities, provided in Table A5 for 2023, were separated by zone using data provided from ERCOT.

Table A5. ERS Capacity by ERCOT Region

Region	ERS Capacity (MW)
Dallas	137
Houston	189
Rest of System	385
Valley	55
West	160
Total	**925**

2. LOAD RESOURCES PROVIDING REAL-TIME RESERVES

Consistent with ERCOT's published minimum Responsive Reserve Service (RRS) requirements, we modeled 1,591 MW of non-controllable load resources (LRs) that actively participate in the RRS market.[17] All 1,591 MW were modeled as responsive to Energy Emergency Alert, Level 2. The magnitude varies by season and time of day. The capacity breakdown modeled by zone is provided in Table A6.

Table A6. Load Resources Capacity by ERCOT Region

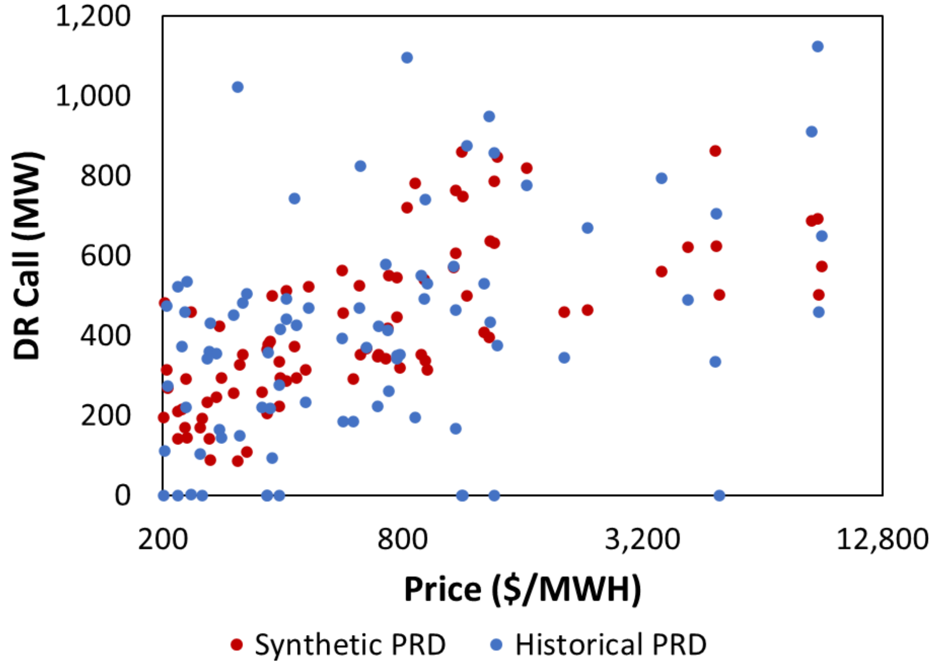
Region	LR Capacity (MW)
Dallas	35
Houston	418
Rest of System	753
Valley	2
West	383
Total	**1,591**

3. PRICE RESPONSIVE DEMAND AND 4-COINCIDENT PEAK

2019 historical demand response was used to develop modeling inputs to replicate stochastic demand-side response for price responsive and 4-coincident peak (4CP) demands. A comparison of historical and synthetic PRD calls is shown in Figure A4. The aggregate of these shapes was split by zone and used to gross up all 42 synthetic weather shapes.

[17] Currently, 1,400 MW is the maximum quantity of non-controllable LRs that are allowed to sell responsive reserve service (RRS) and is the clearing quantity in the vast majority of hours.

Figure A4. Comparison of Historical and Synthetic PRD Calls



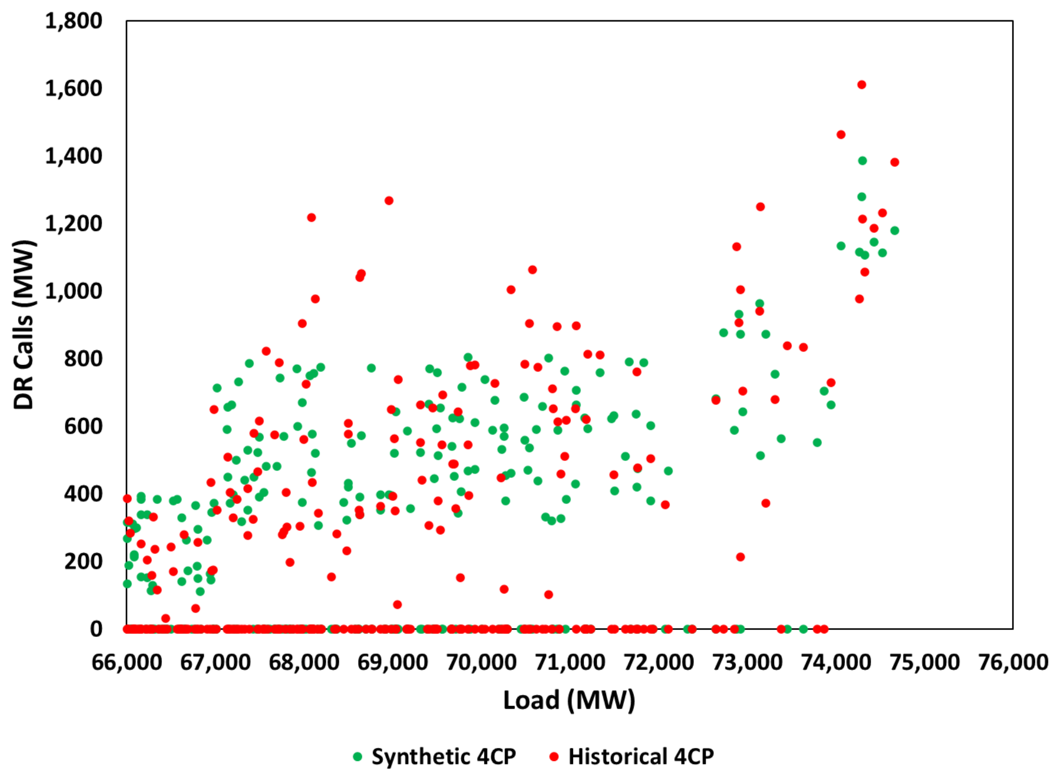
To model the price responsive demand (PRD) in SERVM, a curtailable unit was created in each zone that points to a price responsive demand curve. The demand curve has 4 pricing points based on the segments: $200, $400, $800, and $1,500. For each of the 4 pricing points, 50 data points were created using created synthetic formulas. Within SERVM, whenever price reached one of the specified threshold points, SERVM randomly picked a DR value from the list of 50 data points. The PRD units were available in all months. The capacity modeled by zone is provided in Table A7.

Table A7. PRD Capacity by ERCOT Region

Region	PRD Capacity (MW)
Dallas	138
Houston	250
Rest of System	821
Valley	9
West	282
Total	**1,500**

Similarly, 4CP was modeled as a load responsive unit. A comparison of historical and synthetic 4CP calls is provided below in Figure A5. Historical hourly 4CP was calculated as the sum of the 4CP Competitive and 4CP NOIE programs.

Figure A5. Comparison of Historical and Synthetic 4CP Calls



To model the 4CP program in SERVM, a curtailable unit was created in each region that pointed to a load responsive demand curve. The demand curve had four load points based on the segments 66,000 MW, 67,000 MW, 72,000 MW, and 74,000 MW. For each of the four load points, 50 data points were created using segment formulas. Within SERVM, whenever load reached one of the specified threshold points, SERVM randomly picked a DR value for each unit from that list of 50 data points. The 4CP units were only available during the months of June to September. The capacity modeled by zone is provided in Table A8.

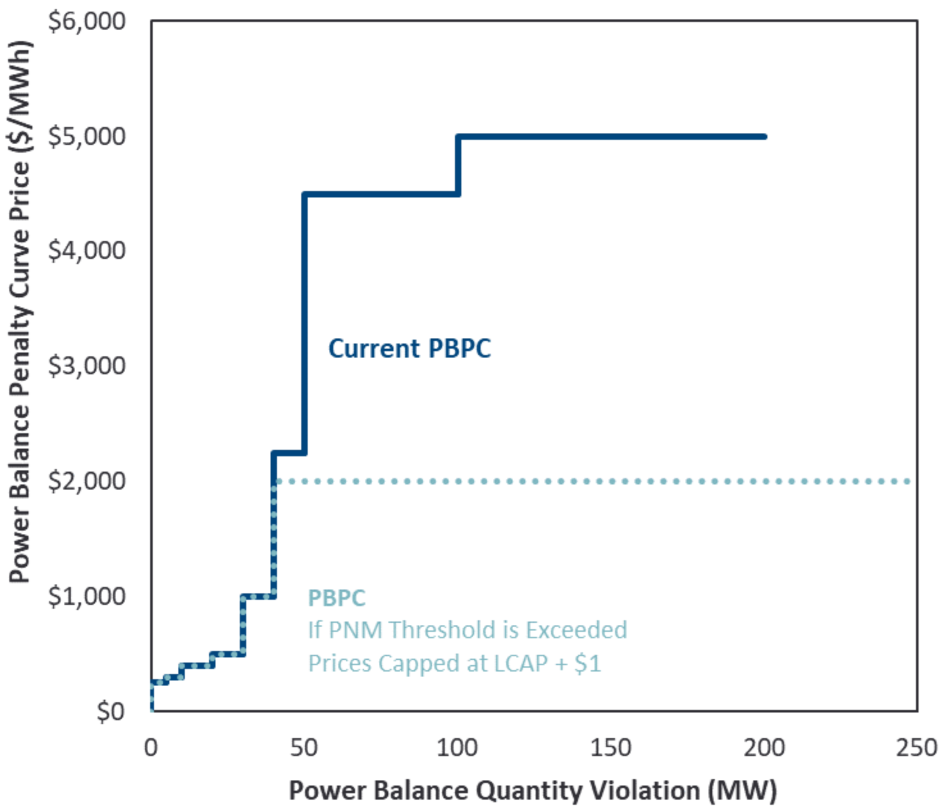
Table A8. 4CP Capacity by ERCOT Region

Region	4CP Capacity (MW)
Dallas	83
Houston	150
Rest of System	492
Valley	5
West	169
Total	**900**

4. POWER BALANCE PENALTY CURVE

The Power Balance Penalty Curve (PBPC) is an ECOT market mechanism that introduces administrative scarcity pricing during periods of supply scarcity. The PBPC is incorporated into the security constrained economic dispatch (SCED) software as a set of phantom generators at administratively specified price and quantity pairs, as summarized in the blue curve in Figure A6. Whenever PBPC is dispatched for energy, it reflects a scarcity of supply relative to demand in that time period that, if sustained for more than a moment, will materialize as a reduction in the quantity of regulating up capability. As the highest price, the PBPC will reach the system-wide offer cap (SWOC) which is set at the HCAP at the beginning of each calendar year, but which will drop to the LCAP if the PNM threshold is exceeded.

Figure A6. Power Balance Penalty Curve



Within SERVM, PBPC is modeled similarly as a phantom supply that may influence the realized price, and that will cause a reduction in available regulating reserves whenever called. However, only the first 200 MW of the curve at prices below the cap are modeled, and it is assumed that all price points on the PBPC will increase according to the schedule SWOC. It is also assumed that the prices in the PBPC are reflective of the marginal cost incurred by going short of each quantity of regulating reserves. Consistent with current market design, we assume that once the PNM threshold is exceeded, the maximum price in the PBPC will be set at the LCAP + $1/MWh or $2,001/MWh.[18] Note that even after the maximum PBPC price

[18] https://www.ercot.com/files/docs/2021/12/14/037OBDRR_01_Power_Balance_Penalty_Updates_to_%20Align_with_PUCT_Approved_High_System_Wide_Offer_Ca.docx

is reduced, ERCOT market prices may still rise to a maximum value of VOLL equal to $5,000/MWh during scarcity conditions because of the ORDC as explained in the following section.

The modeled capacity for PBPC within each zone in SERVM is defined in Table A9.

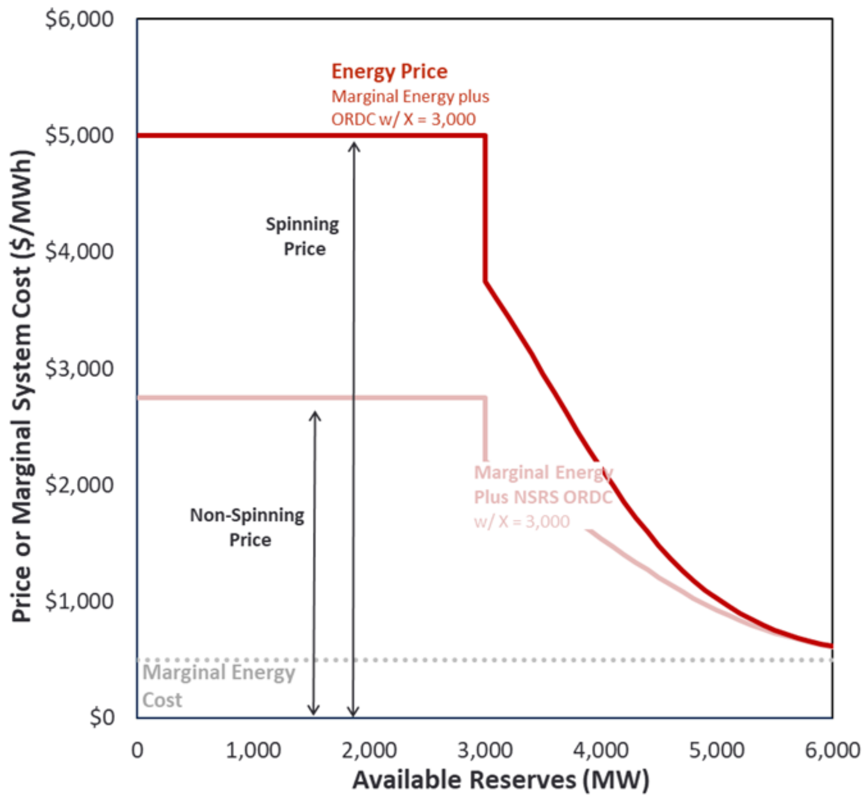
Table A9. PBPC Capacity by ERCOT Region

Region	PBPC Capacity (MW)
Dallas	50
Houston	42
Rest of System	77
Valley	6
West	24
Total	**200**

5. OPERATING RESERVES DEMAND CURVE

The most important and influential administrative scarcity pricing mechanism in ERCOT is the ORDC that reflects the willingness to pay for spinning and non-spinning reserves in the real-time market. Figure A7 illustrates our approach to implementing ORDC in our modeling, which is similar to ERCOT's implementation, with some simplifications.

Figure A7. Operating Reserve Demand Curves



The ORDC curves were calculated based on a loss of load probability (LOLP) at each quantity of reserves remaining on the system, multiplied by the value of lost load (VOLL) caused by running short of operating reserves.[19] This curve reflects the incremental cost imposed by running short of reserves and is added to the marginal energy cost to estimate the total marginal system cost and price.

The x-axis of the curve reflects the quantity of operating reserves available at a given time, where: (a) the spin ORDC includes all resources providing regulation up or RRS, suppliers that are online but dispatched below their maximum capacity, hydrosynchronous resources, non-controllable load resources, and 10-minute quickstart; and (b) the spin + non-spin ORDC include all resources contributing to the spin x-axis as well as any resources providing NSRS and all 30-minute quickstart units. Table A10 provides a summary of the resources in the model that were always available to contribute to the ORDC x-axis unless they were

[19] Note that the lost load implied by this function and caused by operating reserve scarcity is additive to the lost load. This is because the LOLP considered in ERCOT's ORDC curve is caused by sub-hourly changes to supply and demand that can cause short-term scarcity and outages that are driven only by small quantities of operating reserves but are not caused by an overall resource adequacy scarcity, which is the type of scarcity we model elsewhere in this study. For simplicity and clarity, we refer to these reserve-related load-shedding events as "reserve scarcity costs" to distinguish them from the load shedding events caused by total supply scarcity. We do not independently review here ERCOT's approach to calculating LOLP, but instead take this function as an accurate representation of the impacts of running short of operating reserves.

dispatched for energy. It should be noted that the realized ORDC x-axis during a given hour in the simulation can be higher (if other resources are committed but not outputting at their maximum capability) or lower (during peaking conditions when some of the below resources are dispatched for energy).

Table A10. Resources Always Contributing to ORDC X-Axis Unless Dispatched for Energy

Reserve Type	MW
Spin X-Axis	
Hydrosynchronous Resources	245
Non-Controllable Load Resources	1,591
Non-Spin X-Axis	
30-Minute Quickstart	5,058
Total Spin + Non-Spin	**6,894**

As in ERCOT's ORDC implementation, we calculated: (a) non-spin prices using the non-spin ORDC; (b) spin prices as the sum of the non-spin and spin ORDC; and (c) energy prices as the sum of the marginal energy production cost plus the non-spin and spin ORDC prices. However, as a simplification we did not scale the ORDC curves in proportion to VOLL minus marginal energy in each hour.[20] Instead, we treated the ORDC curves as fixed with a maximum total price adder of VOLL minus $500. This caused prices to rise to the cap of $5,000/MWh in scarcity conditions, because $500 is the cap placed on marginal energy prices in the model. Higher-cost demand-response resources were triggered in response to high ORDC prices and therefore prevented prices from going even higher but did not affect the "marginal energy component" of price-setting. We modeled the ORDC curves out to a maximum quantity of 8,000 MW where the reserve price adders were zero.

These ORDC curves create an economic incentive for units to be available as spinning or non-spinning reserve, which influences suppliers' unit commitment decisions. We therefore modeled unit commitment in two steps: (1) a week-ahead optimal unit commitment over the fleet, with the result determining which long-lead and combined cycle resources will be committed;[21] and (2) an hourly economic dispatch that dispatches online baseload units, and can commit 10-minute and 30-minute quickstart units if needed to satisfy energy or ancillary service requirements.[22] Note that 10-minute quickstart units can earn spin

[20] See ERCOT's implementation in http://lmpmarketdesign.com/papers/Back_Cast_of_Interim_Solution_B_Improve_Real_Time_Scarcity_Pricing_Whitepaper.pdf

[21] Short-term resources are included in the week-ahead commitment algorithm, but their commitment schedule is not saved since it will be dynamically calculated in a shorter window. But using short-lead resources in the week-ahead commitment allows them to affect the commitment of long-lead resources.

[22] These week-ahead and day-ahead commitment algorithms minimize cost subject to meeting load as well as ERCOT's administratively determined regulation up, spinning reserve targets, and non-spin targets.

payments from an offline position while 30-minute quickstart units can earn non-spin payments from an offline position. The model did not allow these resources to self-commit unless doing so resulted in greater energy and spin payments (net of variable and commitment costs) than would be available from an offline position. We used a similar logic to economically commit or de-commit units until the incentives provided by the ORDC were economically consistent with the quantity of resources turned on.