ercot
Your Power. Our Promise.

TAYLOR
2705 West Lake Dr.
Taylor, Texas 76574
T: 512-248-3000
F: 512-225-7079

AUSTIN
8000 Metropolis Dr.
Bldg. E, Suite 100
Austin, Texas 78744
T: 512-225-7000
F: 512-225-7079

ercot.com

October 10, 2023

Public Utility Commission of Texas
Interim Chairman, Kathleen Jackson
Commissioner Will McAdams
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty
1701 N. Congress Avenue
Austin, TX 78711

Re: PUC Project No. 54584, *Reliability Standard for the ERCOT Market*

Dear Chairman and Commissioners:

As requested by Commissioner McAdams' Memorandum and the Commissioners at the September 28, 2023 Open Meeting,[1] please find attached a table describing the inputs to and assumptions incorporated into the Strategic Energy & Risk Valuation Model (SERVM) that ERCOT is using to perform the reliability standard study iterations. A description of the model's outputs and reliability measures is also included.

Information responsive to the nine questions included in Commissioner McAdams' Memorandum is addressed below. Additional explanation to assist with interpreting exceedance probabilities and associated probability targets is also included as a tenth comment.

ERCOT representatives will be available at the October 12, 2023 Open Meeting to present this information and answer any questions that you may have.

Respectfully submitted,

/s/ Kristi Hobbs

Kristi J. Hobbs
Vice President
System Planning & Weatherization
khobbs@ercot.com

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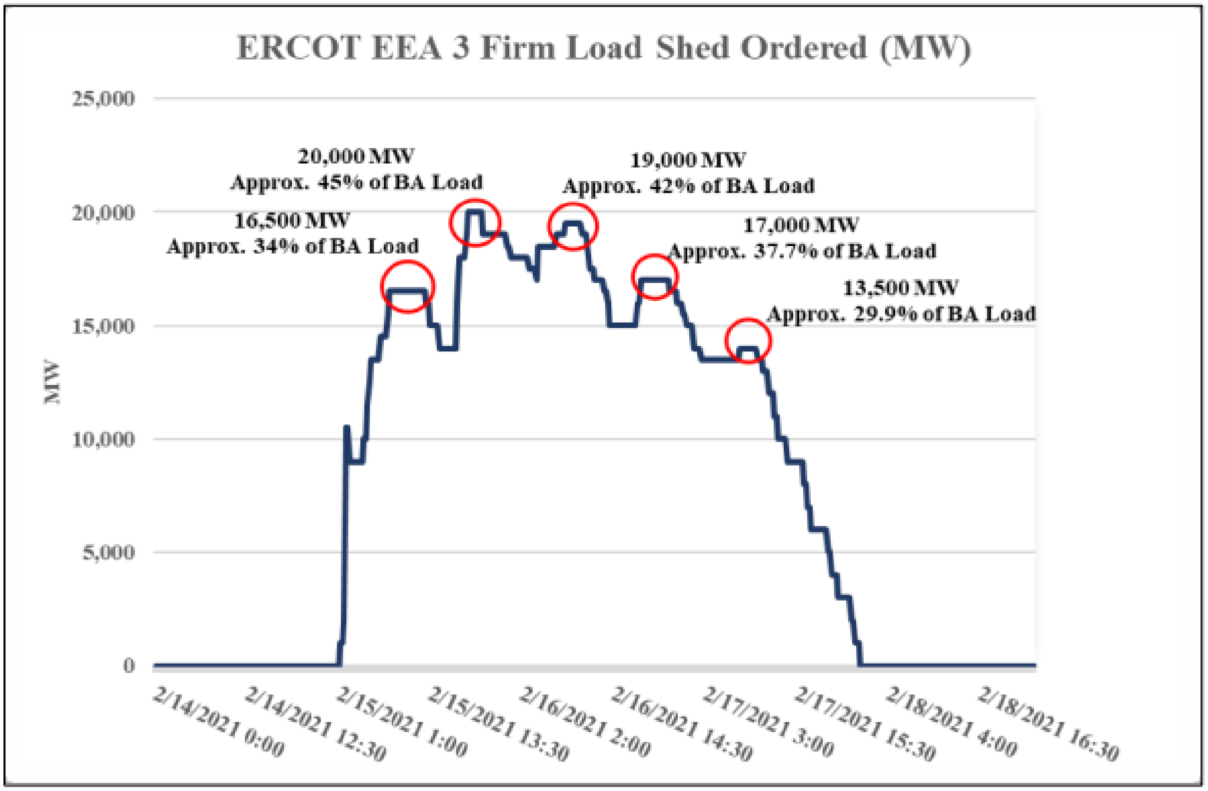
[1] *See Reliability Standard for the ERCOT Market,* Project No. 54584, Memorandum (Sept. 27, 2023).

1. **Please provide the magnitude and duration of the outages during the winters of 2011 and 2021 in the context of the study.**

The physical firm load shed on February 2, 2011, reached a maximum of 4,000 megawatts (MW) and extended for just over seven hours.[2] However, the estimated load without curtailments was over 6,000 MW higher than actual load during the peak of the load shed event. Load shed in February 2021 peaked at 20,000 MW and extended for nearly 72 hours.[3] The chart below shows the sequence and timing of load shed events for Winter Storm Uri.

Figure 85: ERCOT EEA 3 Energy Emergency Firm Load Shed Ordered (MW)

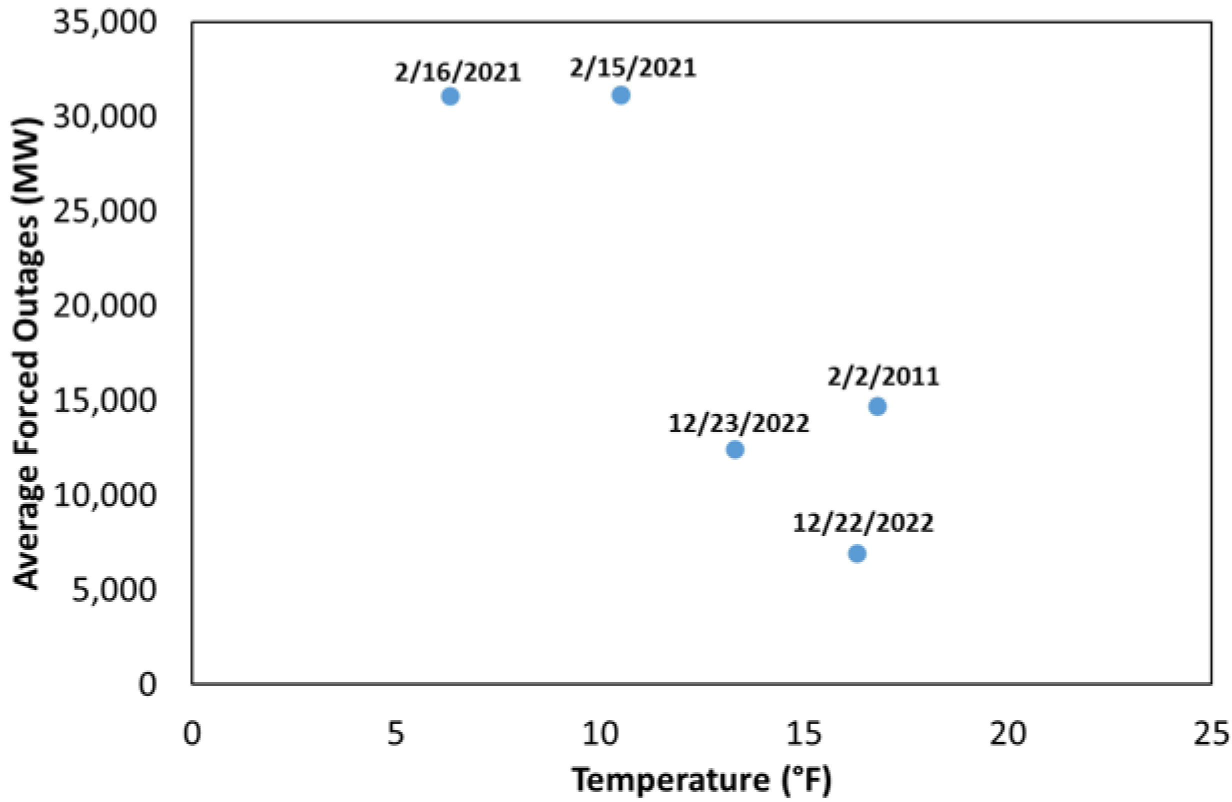


The key driver of load shed during both winter storm events was conventional generator outages. In 2011, a maximum of 15 gigawatts (GW) of conventional generation was forced offline and an additional 12 GW of generation was unavailable due to planned maintenance. During Winter Storm (WS) Uri in 2021, a maximum of over 30 GW of conventional capacity was on unplanned (i.e., forced) outage and several GW of conventional capacity was on planned maintenance outages. The chart below shows the average unplanned outage amounts for the three

[2] *See* Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 (Aug. 2011), available at: https://www.ferc.gov/sites/default/files/2020-05/ReportontheSouthwestColdWeatherEventfromFebruary2011Report.pdf.

[3] *See* FERC, NERC, and Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 16, 2021), available at: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

storm events (February 2011, WS Uri, and WS Elliott) in relation to the average ERCOT-wide temperature during the events. The outage amounts include both planned and unplanned outages.



2. **Please provide a comparison of the "Total Variable Cost" to the actual historical market costs.**

Since SERVM is simulating 2026, the simulated costs would be considerably different than historical market costs. ERCOT proposes providing a cost comparison based on 2023 prompt-year simulation results. The appropriate cost value from SERVM would be the Customer Cost described in the "Key SERVM Outputs and Reliability Measures" attachment. The comparison would be with the actual 2022 market cost.

3. **Please describe how the results of the VOLL study will be incorporated with the SERVM model runs? Will the model be able to reflect different VOLLs for different customer classes?**

SERVM uses a single Value of Lost Load (VOLL) parameter to quantify the cost of unserved energy for the system. The VOLL study results can be used to create a single weighted-average value based on the customer class values, as well as sensitivities based on setting VOLL to specific customer class values. As part of the last ERCOT reserve margin study, VOLL sensitivities from $5,000 to $30,000 per megawatt hour (MWh) were evaluated for their impact on the Economically Optimal Reserve Margin (EORM). VOLL also influences the Operating Reserve Demand Curve (ORDC). A separate ORDC modeling is required to analyze the effects of alternate VOLL estimates on market prices. The VOLL sensitivity analysis performed as part of the most recent reserve margin study was strictly a sensitivity on the cost of load shed events and did not assess the inputs to the ORDC.

4. Please explain how distributed energy resources (DERs) are incorporated in the SERVM model including settlement only distributed generators, distributed generation resources, and unregistered DERs.

All distributed generation resources reported in the May 2023 Capacity, Demand, and Reserves (CDR) Report are included in SERVM. The categories include the following:

- Solar, wind, biomass, hydro, and battery storage Settlement Only Distributed Generators (SODGs)
- Distributed Generation Resources, all fuel/technology types

While fossil fuel SODGs are listed in the CDR, they are not included in reserve margin calculations because most are emergency standby generators or already participate in Demand Response programs or Emergency Response Service via on-site load reductions.

Unregistered Distributed Generators (mostly rooftop solar installations) are accounted for as load reductions in the ERCOT Long Term Load Forecast.

5. How do size and location of generation resources affect the model results?

A larger generation resource will have a more adverse impact on reliability than several smaller resources that, in aggregate, have the same size and operational characteristics as the larger resource (with all else held constant).

The geographic impact of wind and solar resources is represented in two complementary ways. First, through different capacity contributions (Effective Load Carrying Capability) assigned to the resources based on their CDR "fuel" zone — Coastal, Panhandle, and Other for wind, and West and Non-west for solar. Second, individual wind and solar sites are represented as synthetic hourly generation profiles that capture weather characteristics at each site going back to 1980. For example, each site has 42 hourly profiles reflecting annual weather (a "weather year") from 1980 through 2021.

Since internal transmission constraints are not currently considered, both effects on results are somewhat muted. The shaft risk of a large generator would be more pronounced if it was in a small zone with restrictive transmission constraints. The value of western solar would be less if export constraints limited its ability to serve load in the east.

6. Are there trends in recent years that deviate in intensity from past years, and does the SERVM model weigh these factors differently, e.g., load growth, unplanned outages, weather?

SERVM allows the user to assign different probabilities to weather years and other scenario cases such as fuel prices. ERCOT has not chosen to apply different probabilities, for example, to weather years based on an assumed continued warming trend and associated increase to loads. This can be done for scenario/input sensitivity analysis. For example, for the last Reserve Margin study, Astrapé calculated an MERM using only the past 15 years of weather data, weather-year load forecasts, and wind/solar weather-year generation profiles. Each of these weather years were assigned the same probabilities (or weights). This scenario resulted in an MERM that was one percentage point higher than the base case, which used 40 weather years weighted equally. A commensurate impact would be observed for a reserve margin with a 0.1 event per year Loss of Load Expectation (LOLE).

For unplanned outages, SERVM uses outage data for a three-year historical period to establish mean-time-to-failure, mean-time-to-repair, and start-up failure rates for stochastic outage modeling. This period length is intended to capture more recent impacts of deferred maintenance, frequent unit cycling, etc. Weather impacts on outages have been modeled to capture the effects of the most recent winter storms such as WS Elliott and WS Uri.

7. Please describe how conservative operations are or are not reflected in the SERVM model. If not, why not?

Protocol changes now allow ERCOT to deploy certain resources prior to an EEA declaration (e.g., Emergency Response Service and Distribution Voltage Reduction). These changes are reflected in SERVM. Recent changes to Ancillary Service procurement are also reflected in the model. Finally, model set-up includes calibration to reflect the recent increases in operating reserves that need to be carried in the model. This calibration would account for Reliability Unit Commitments (RUCs). The effect of Real Time Co-optimization can be incorporated once there is operational data with which to support calibration efforts in future instances of SERVM.

8. Are historical gas pipeline constraints or deliverability issues reflected in the SERVM model?

While SERVM has the capability of modeling the physical fuel system, including pipelines and alternate fuel sources, gas pipeline constraints and deliverability issues are not currently explicitly accounted for in ERCOT's implementation of SERVM. Historical outages caused by "fuel limitations" are included in the calculation of unit-specific Equivalent Forced Outage Rates (EFORs) used for SERVM's probabilistic outage modeling. The cold weather outage modeling explicitly factors in generator outages caused by fuel issues based on historical performance, but because all cold weather outages are aggregated, it does not provide insight into the isolated impacts of fuel supply issues.

9. Could transmission and distribution outages be incorporated into the SERVM model in the future? ERCOT and Commission Staff had recommended a separate deliverability study once the final market design is implemented. What do you think that would look like?

Astrapé performed a zonal reliability study for ERCOT in 2022 which analyzed the impact of internal ERCOT transmission constraints. The results of the analysis showed that 3 to 4 GW of location-sensitive additional generation or 2 to 3 GW of additional transmission capability between each interconnection would be required to maintain a 0.1 LOLE as compared to the resource requirements in a scenario which assumed unlimited internal transmission capability.

More comprehensive deliverability analysis that considers probabilistic transmission and distribution outages could also be performed in SERVM. Reflecting these outages would raise modeled reliability risk.

10. Interpreting Exceedance Probabilities and Associated Probability Targets

The exceedance probabilities in the scenario results table attached to the September 21, 2023 filing in Project No. 54584 indicate the percentage of loss-of-load events that exceed the given magnitude and duration criteria established for the scenarios. For example, the following table summarizes the scenario attributes and results for Scenario No. 29:

Scenario #29		
Portfolio Attributes	Resource Mix Type	CDR Mix
	Incremental Coal Retirements (MW)	3,300
Measure Criteria	Frequency	1 in 5
	Duration (Hrs)	10
	Magnitude (MW)	10,000
Exceedance Probabilities	**Duration**	**4.90%**
	Magnitude	**6.86%**

For this scenario, the portfolio was developed such that it results in a 1-in-5 expected loss-of-load frequency. The exceedance probabilities indicate that 4.9% of the loss-of-load events exceed the 10-hour duration criterion, while 6.9% of the loss-of-load events exceed the 10,000 MW magnitude criterion. In other words, for this portfolio, there would be events that have durations greater than 10 hours and magnitudes greater than 10,000 MW. If the Commission set the reliability standard to these frequency, duration, and magnitude levels, for this resource portfolio, the occurrence of outlier events (those with low probability but high impact) would be an acceptable risk.

Exceedance probabilities can be reduced by decreasing the frequency criterion (e.g., 1-in-5 to 1-in-10), increasing the duration and magnitude criteria, or a combination of approaches. Selecting exceedance probability targets can then be used to eliminate combinations of measure criteria for further consideration. For example, focusing on the CDR Mix portfolios with the 3,300 MW incremental coal retirement scenario, if the Commission selects a 3% exceedance probability target, the table below shows which scenarios are eliminated for further consideration (five out of the original 12).

	Reliability Standard Framework Inputs			Scenario Parameters				
No.	FREQUENCY (LOLE)	DURATION (Hours)	MAGNITUDE (MW)	MW Retired	Portfolio	Exceedance Probability Required for Duration	Exceedance Probability Required for Magnitude	
13	1 in 5	15	14,000	3,300	CDR Mix	0.02%	3.05%	Eliminate
14	1 in 10	15	14,000	3,300	CDR Mix	0.00%	0.57%	
15	1 in 15	15	14,000	3,300	CDR Mix	0.00%	0.13%	
16	1 in 20	15	14,000	3,300	CDR Mix	0.00%	0.10%	
29	1 in 5	10	10,000	3,300	CDR Mix	4.90%	6.86%	Eliminate
30	1 in 10	10	10,000	3,300	CDR Mix	1.66%	2.78%	
31	1 in 15	10	10,000	3,300	CDR Mix	0.30%	1.09%	
32	1 in 20	10	10,000	3,300	CDR Mix	0.19%	0.78%	
45	1 in 5	5	5,000	3,300	CDR Mix	5.89%	10.82%	Eliminate
46	1 in 10	5	5,000	3,300	CDR Mix	3.31%	6.67%	Eliminate
47	1 in 15	5	5,000	3,300	CDR Mix	1.81%	3.75%	Eliminate
48	1 in 20	5	5,000	3,300	CDR Mix	1.41%	2.90%	

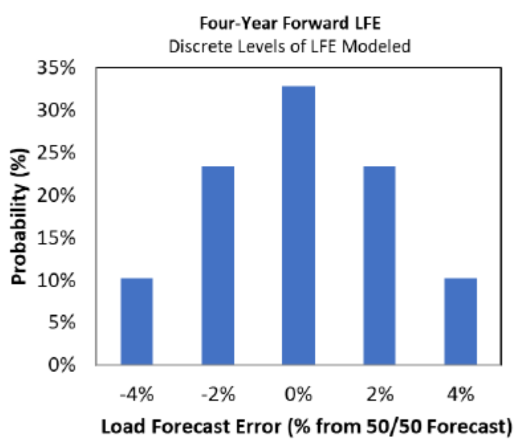
SERVM Inputs and Assumptions

Model Inputs	Description	References
Cost of New Entry (CONE)	In consultation with the Independent Market Monitor (IMM), the current value used for CONE is $119 per MW-year based on an advanced Combustion Turbine (CT) generation technology with an overnight construction of $950 per kW and a Weighted Average Cost of Capital (WACC) of 7.9%. Several cost estimates were evaluated, such as the U.S. Department of Energy's Annual Energy Outlook, Lazard's "Levelized Cost of Energy" (LCOE) report, PJM's April 2023 CONE study, S&P Global Market Intelligence, National Energy Technology Laboratory (NETL) and other public information regarding construction of flexible peaking units (aeroderivative CTs) similar to projects in the ERCOT region.	The latest CONE study for PJM is available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx The Lazard LCOE report is available at: https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/ NETL's baseline cost and performance report for "Natural Gas Electricity Generating Units for Flexible Operation" is available at: https://www.osti.gov/servlets/purl/1973266
Coal and natural gas prices	Natural Gas The delivered annual natural gas price is $3.33 per MMBtu. The source is the U.S. Energy Information Administration's (EIA) 2022 Annual Energy Outlook Reference Case for gas price futures. The annual price is scaled to monthly values by multiplying it by the ratios of the average historical monthly Henry Hub spot price divided by annual average Henry Hub spot price. Coal The delivered coal price is $2.21 per MMBtu and represents the average coal price for coal power plants in the ERCOT region based on EIA Form 923 data.	The EIA's 2022 Annual Energy Outlook Reference Case is available at: https://www.eia.gov/outlooks/archive/aeo22/ EIA Form 923 data is available here: https://www.eia.gov/survey/#eia-923
Value of Lost Load (VOLL)	The VOLL parameter is currently set to $5,000 per MWh. VOLL affects the modeled Operating Reserve Demand Curve (ORDC), and thus affects market prices produced by the model.	Background on the use of the VOLL as an ORDC parameter is available at: https://www.ercot.com/files/docs/2022/10/31/2022%20Biennia

Model Inputs	Description	References
		l%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf
Energy Emergency Alert (EEA) Triggers	SERVM reflects the new EEA capacity triggers outlined in Nodal Protocol Revision Request 1176: EEA1 – 2,500 MW EEA2 – 2,000 MW EEA3 – 1,500 MW	See the NPRR1176 Board Report, available at: https://www.ercot.com/files/docs/2023/09/06/1176NPRR-12%20Board%20Report%20083123.docx
Weather-Year Profiles	SERVM uses historical hourly temperatures and wind chill temperature to create annual weather profiles going back to 1980. The temperature profiles are used to support probabilistic modeling of the weather-dependent component of load and certain resources (wind and solar) as well as temperature-related thermal unit unplanned outages. The historical temperature data —average weighted values by ERCOT weather zones—comes from MDA (Maxar), which is ERCOT's vendor of record for weather observations. SERVM runs each discrete weather scenario but can apply different weights (probabilities) for each weather profile. For the Reliability Standard study, equal weights are applied to all 42 weather profiles in the model.	
Resource Mix (Installed Capacity Basis)	<u>Base Portfolio for 2026 (November 2022 Capacity, Demand, and Reserves (CDR) report)</u> Coal – 13,630 MW Gas – 55,415 MW Nuclear – 4,973 MW Wind – 41,853 MW Solar – 44,775 MW Battery Storage – 10,945 MW Hydro – 563 MW Biomass – 174 MW	

Model Inputs	Description	References
	<u>Incremental Resources to Approximately Match May 2023 CDR Planned Resources (CDR Mix Scenarios)</u> Gas CT – 4,081 MW (1-in-10 frequency), 7,791 MW (1-in-15 frequency), 8,904 MW (1-in-20 frequency) Solar – 782 MW Battery Storage – 3,082 MW	
Thermal Resource Unplanned Outage Modeling, Non-Weather-Related	Outages are modeled stochastically (as random events) for each thermal generator. Historical outage event data from NERC's Generator Availability Data System (GADS) from 2018 to 2023 is used to develop "calibration" Equivalent Forced Outage Rates (EFORs) for the units. Time-to-Fail and Time-to-Repair distributions are entered for each unit based on the historical GADS event data. SERVM then uses Monte Carlo draws to generate random forced outages. The calibration EFORs are used to verify that the units' modeled EFORs are reasonable and that the aggregated probability distributions are reasonable.	
Thermal Resource Unplanned Outage Modeling, Weather-Related	Cold and hot weather-related outages are modeled as a function of temperature by ERCOT weatherization zone and outage probability. For the winter season, wind chill temperatures are used. The winter outage probabilities are based on an analysis of unplanned outages that occurred during extreme winter storm events (February 2011 and named winter storms Uri, Elliott, and Mara). The modeling also assumes that weatherization efforts reduce all weather-related unplanned outages by 85% (excludes outages due solely to fuel curtailments). Note that the weather-related outages are determined independently of, and added to, the outages caused by non-weather-related causes.	See the Supply Analysis Working Group presentation on weather-based thermal outage modeling, available at: https://www.ercot.com/files/docs/2023/08/23/4__Weather-based_Thermal_Outage_Modeling.pptx
Planned Thermal Outage Modeling	SERVM schedules planned outages in advance of each hourly simulation based on a scheduled maintenance rate. Consistent with market operations, the planned outages occur during low demand periods in the spring and fall, such that	

Model Inputs	Description	References
	the highest coincident planned outages occur in the lowest load days.	
Scarcity Pricing	During emergency and other peaking conditions, SERVM simulates scarcity prices that exceed generators' marginal production costs based on administrative scarcity pricing.	
Transmission and Distribution Service Provider (TDSP) Standard Offer load management programs	TDSP load management programs are modeled as dispatchable resources with a call limit of 16 to 48 hours per year. The model deploys program capacity when operating reserves reach an EEA Level 2. Deployed amounts are 307 MW during the summer season and 144 MW during the winter season.	
Operating Reserve Demand Curve (ORDC)	SERVM models the ORDC with the multi-step On-Line Price Adder floor, as recommended by ERCOT and voted on by the ERCOT Board of Directors on April 18, 2023.	The Board voting item is available at: https://www.ercot.com/files/docs/2023/04/11/10.1%20Phase%202%20Market%20Redesign%20-%20Bridging%20Solutions.pdf
Power Balance Penalty Curve (PBPC)	SERVM models the PBPC up to a Power Balance Quantity Violation of 200 MW.	See the 2022 Effective Load Carrying Capability (ELCC) Study report, available at: https://www.ercot.com/files/docs/2022/12/09/2022-ERCOT-ELCC-Study-Final-Report-12-9-2022.pdf Refer to pages 62-63 for more background on PBPC modeling.
Load Forecast and Modeling Weather Uncertainty	<u>Hourly Load Forecasts by Weather Zone and Historical Weather Year</u> ERCOT's load forecasting department developed new 2026 hourly load forecasts by weather zone to support the modeling study. To create a weather zone forecast for each historical weather year, the hourly historical temperatures for each weather zone are run through the forecasting model. A	

Model Inputs	Description	References
	total of 43 weather-year load forecasts were prepared, spanning 1980 through 2021. <u>Weather-Year Load Forecast Usage for Monte Carlo Simulation</u> SERVM simulates each discrete weather scenario. When a weather year is selected, the hourly loads for that weather year are used in the simulation as well as the associated hourly profiles for wind and solar generation to maintain time synchronization among these weather-dependent variables.	
Modeling Non-weather-based Load Forecast Uncertainty	In addition to modeling weather-based load uncertainty, SERVM also models non-weather-based load error. Five discrete percentage levels of load forecast error are simulated, with probabilities that approximate a normal distribution. The levels comprise 0%, +/−2%, and +/−4% above and below the 50^{th} percentile weather zone forecasts. The following table shows the load forecast error levels and associated probabilities.  	A more detailed description of this modeling approach is available at: https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf
Emergency Response Service (ERS)	ERS is modeled as three distinct generation units, each representing the 10-minute, 30-minute, and weather sensitive ERS products. Each ERS unit has an hourly profile based on the procurement results for each of the last four ERS Standard Contract Terms (SCTs). For example, winter profile values	The link to ERS procurements by Contract Period is available at: https://www.ercot.com/mp/data-products/data-product-details?id=NP3-144-M

Model Inputs	Description	References
	are based on the procurement results posted on 11/28/2022 for the winter SCT. ERS unit dispatch by SERVM is constrained to the designated time periods for the applicable SCTs, as well as up to a maximum of 24 cumulative hours in a SCT. There are no limits to the number of times that an ERS unit can be dispatched, subject to the above operational constraints.	
Wind and Solar Resource Representation	<u>Operational and Planned Capacity</u> Wind and solar resource installed capacity (nameplate) for 2026 comes from the November 2022 CDR. The CDR mix scenario reflects incremental planned capacity as reported in the May 2023 CDR. Resources in the CDR are assumed to be available as of January 1, 2026. <u>Weather-Year Synthetic Generation Profiles</u> UL Renewables develops hourly synthetic generation profiles for each solar site (operational and planned) and historical weather year going back to 1980. Each site thus has 42 hourly profiles for weather years 1980 through 2021. To utilize the profiles in SERVM, Astrapé converted the hourly generation values to capacity factors, i.e., normalized the values to each unit's nameplate capacity. The capacity factors are then multiplied by the units' nameplate capacities during the simulations. <u>Profile Usage for Monte Carlo Simulation</u> SERVM simulates each discrete weather scenario. For the simulation, the model uses the solar and wind site profiles for that weather year, along with the load forecast profile, to maintain time-synchronization among the inputs dependent on hourly weather conditions.	The link to the profile development report is available at: https://www.ercot.com/files/docs/2022/12/19/ERCOT_1980-2021_WindSolarGenProfiles_FINAL_public.pdf.
Hydropower Representation	Energy from hydro units is primarily scheduled by SERVM to shave peak loads consistent with historical operations. Historical operations are represented as output profiles using 42 years of	

Model Inputs	Description	References
	monthly data modeled with different parameters for each month (monthly total energy output, daily maximum output, daily minimum output, and monthly maximum output) based on eight years of hourly data from ERCOT and 42 years of monthly generation data from EIA Form 923. The hydro modeling also reflects an emergency capacity of 49 MW modeled for drought conditions as defined by low hydro energy availability and 116 MW modeled for all other months.	
Battery Storage Resource Representation	SERVM's unit commitment process optimizes the utilization of storage resources to minimize system production costs while meeting all load and Ancillary Service obligations. An initial charging and discharging schedule is determined prior to unit commitment using net load and market prices from prior iterations. Every charging and discharging cycle must overcome roundtrip cycle efficiency losses and any variable O&M expense associated with either charging or discharging. All storage units are modeled with an 85% round trip efficiency and a 5% forced outage rate. "Battery RFI Summary Reports" are used to determine the storage duration for listed units and an average of the durations is used for the units without data available (1.5 hours). "Co-Located Battery Identification Reports" are used to determine whether storage units are co-located, self-limiting, or stand-alone. Within SERVM, batteries that are co-located are forced to only charge from the solar or wind unit that they are tied to and have a defined maximum combined capacity. Battery units without linked solar or wind units can charge from the grid.	
Distributed Energy Resources	All distributed generation resources reported in the November 2022 CDR report are included in SERVM. The categories include the following:	

Model Inputs	Description	References
	• Solar, wind, biomass, hydro and battery storage Settlement Only Distributed Generators (SODGs) • Distributed Generation Resources, all fuel/technology types While fossil fuel SODGs are listed in the CDR, they are not included in reserve margin calculations because most are emergency standby generators or already participate in Demand Response programs or ERS via on-site load reductions. Unregistered Distributed Generators (mostly rooftop solar installations) are accounted for as load reductions in the ERCOT Long Term Load Forecast.	
Transmission Representation	SERVM has multi-area reliability and economic dispatch modeling capability, where inter-area transmission constraints can be simulated. For the Reliability Standard modeling, SERVM incorporates economic optimization of transmission-constrained power flows across the DC ties with SPP, MISO, and Mexico to minimize costs, consistent with prior ERCOT reliability assessment studies. ERCOT is treated as a single area. Astrapé performed a zonal reliability impact study in 2022 to investigate the feasibility and challenges of determining how a target reliability standard level (1-in-10-year loss-of-load frequency (LOLE)) can be maintained through regional generation capacity additions and transmission expansion between regions.	The zonal reliability study is available at: https://www.ercot.com/files/docs/2023/01/10/ERCOT_Zonal_Reliability_Study_Report_1-9-2023.pdf
Ancillary Service Modeling	SERVM models Ancillary Services as hourly profiles based on the "ERCOT AS Quantities" Excel workbook for 2023, posted to ercot.com. AS hourly profiles were created for Responsive Reserve Service-Primary Frequency Reserves (RRS-PFR), RRS from Load Resources, Regulation-Up,	ERCOT AS Quantities file for 2023 is available at: https://www.ercot.com/files/docs/2022/06/07/Zip%20to%20be%20posted%20060923.zip

Model Inputs	Description	References
	Regulation-Down, Non-Spinning Reserve, and ERCOT Contingency Reserve Service (ECRS).	
Price Responsive Demand and 4-Coincident Peak (4CP) Program	Load reduction impacts of Price Responsive Demand (including standalone Large Flexible Loads) and 4CP load reductions are already embedded in the weather-year load forecasts.	
Private Use Network (PUN) Generators	The summer and winter capacity contributions of PUN generators in the model are 2,798 MW and 3,348 MW, respectively. PUN generators are modeled as load-responsive resources based on historical hourly net MW injection data. To represent net injection probabilistically, SERVM includes supply “bands” with values that the model can select randomly based on the percentage of hourly load to the normal system peak load for the given hour. As the load percentage increases, the model selects a higher amount of net injection, with the amount selected being one of ten possible values with each having a 10% chance of selection.	See the 2022 ELCC Study report, available at: https://www.ercot.com/files/docs/2022/12/09/2022-ERCOT-ELCC-Study-Final-Report-12-9-2022.pdf Refer to pages 20-21 for more background on the PUN generator modeling approach.
Gas Transportation Constraint Representation	ERCOT’s SERVM implementation does not directly model gas pipeline or delivery constraints. SERVM can model firm and non-firm gas transportation and associated availability when the daily minimum temperature falls below a designated value. While gas transportation constraints are not reflected in the model, their historical impact on aggregate gas unit outages is accounted for.	
Firm Fuel Supply Service (FFSS) Representation	Outage improvement for gas units participating in FFSS is represented as a 125 MW perfect gas unit that provides a linear outage reduction improvement ranging from 50 MW to 125 MW as wind chill temperature decreases. The 125 MW unit size represents the fraction of the total gas fleet (64,130 MW) that is FFSS Resource capacity based on the procurement for winter 2022-23 (2,940.5 MW).	More details on modeling avoided outages due to FFSS is available at: https://www.ercot.com/files/docs/2023/08/23/4__Weather-based_Thermal_Outage_Modeling.pptx

Key SERVM Outputs and Reliability Measures:

- Loss-of-Load (LOL) Event: An hour during which firm load plus 1,500 MW of operating reserves exceeds available generation capacity. SERVM tracks LOL Events as the count of days with at least one loss-of-load hour. The associated reliability measure ("frequency") is the Loss of Load Expectation (LOLE). LOLE is the average number of days with at least one LOL Event for all 5,250 simulations conducted for each scenario.
- Loss-of-Load Hours (LOLH): The count of the hours in a simulation with unserved load (a LOL Event). The LOLH reliability measure is the average number of hours with unserved load for all 5,250 simulations conducted for each scenario.
- Unserved Energy: The total amount of load lost (in MWh) for a simulation. The associated reliability measure is the Expected Unserved Energy (EUE), which is the average Unserved Energy for all 5,280 simulations conducted for each scenario.
- Hourly Generation Dispatch: The operating status of every unit for every hour in the weather year in specific iterations or an average of all iterations can be created.
- Ancillary Services: The sum of each hourly Ancillary Service amount supplied: regulation-up, regulation-down, spin-supplied (including ECRS), and non-spin. SERVM also provides the weighted price of each Ancillary Service.
- Hourly/Annual Production Costs: The sum of fuel cost, variable operations & maintenance costs, and start costs.
- Customer Costs: Calculated outside the model using outputs from the system metrics report (Customer Costs = Load * Market Price + Spin Supplied * Spin Weighted Price + Reg-Up Supplied * Reg-Up Weighted Price + Non-Spin Supplied * Non-Spin Weighted Price). Note that Spin plus Reg-Up represents all real-time online reserves. For this calculation, SERVM distinguishes only Spin and Reg-Up because separate online reserve variables for modeling various emergency actions are used. Reg-Up is 1,500 MW to reflect the amount preserved during load shed. "Spin Supplied" captures all other real-time online reserves.
- Market Prices: The annual average or hourly market prices; includes the energy price plus the larger of the spin or regulation-up price.
- Net Import Costs: The hourly purchase costs for energy minus sales revenue.
- Load Shed Costs: The EUE due to capacity shortage multiplied by the Value of Lost Load (as noted in the descriptions table, VOLL is $5,000 per MWh).
- Generator Net Energy Revenue: The sum of energy revenue, regulation revenue, and spin revenue.