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April 4, 2024

Public Utility Commission of Texas
Chairman, Thomas J. Gleeson
Commissioner Kathleen Jackson
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:

Electric Reliability Council of Texas, Inc. (ERCOT) submits this update regarding the Reliability Standard for the ERCOT Market. Since the last update, ERCOT has completed the modeling of the final proposed reliability standard study scenarios and completed the initial steps in the Cost of New Entry (CONE) study. Presentations regarding the reliability standard study results and CONE reference technology are included for your review.

Reliability Standard Study Modeling

ERCOT has completed the modeling of the phase four reliability standard study scenarios (included here as Attachment C). As proposed at the Public Utility Commission of Texas' (Commission) January 18, 2024 Open Meeting, this phase of work further limited the range of Loss-of-Load Expectation (LOLE) frequency scenarios, simulated smaller LOLE increments within that range, and updated the scenario portfolios based on the December 2023 Capacity, Demand, and Reserves (CDR) Report. The attached presentation provides an overview of the system cost analysis for phase four, including background on the study design and comparison of high system cost years (Attachment B). Also provided is an analysis of the seasonal solar and wind capacity equivalents that would be necessary to replace the combustion turbine capabilities simulated in the Strategic Energy & Risk Valuation Model (SERVM).

During the analysis of the additional reliability standard study runs, ERCOT discovered a bug impacting battery scheduling simulations in SERVM. The issue produced erroneous negative market prices during negative net load hours, thereby resulting in the over-curtailment of solar resources and depressed market costs. Astrape corrected the bug in SERVM and ERCOT reran the previous 76 scenarios simulated for phase three that were previously filed with the Commission in January. The revised scenarios are included in the attached reliability standard study results tables. Overall, there was a substantial increase in market costs and a general increase in portfolio reliability.

CONE Study Update

ERCOT has engaged The Brattle Group (Brattle) to conduct a study to determine one or more CONE values. These values may be used for various market and reliability-related purposes, including calculating the value of Performance Credits under the Performance Credit Mechanism (PCM) and the Peaker Net Margin.

ERCOT formalized its study engagement with Brattle in December 2023. Brattle has now completed the first two steps of the engagement—specifically, identifying a primary and alternative reference generation technology. The primary reference technology is intended to be an example of a thermal, dispatchable generation plant that is likely to be developed in the next few years. Based on recently built and planned thermal dispatchable generation, the primary reference technology identified by Brattle is a ProEnergy GE LM6000 combustion turbine operating in a 6 x 0 configuration, providing an aggregate capacity of 484 MW, and located in Harris County.

The alternative reference technology is intended to be an example of a dispatchable renewable plant that is most likely to be developed in the ERCOT Region in the next few years and that may be used as a basis for sensitivity analysis of the primary case. Based on recently built and planned projects, the alternative reference technology identified by Brattle is a hybrid solar-storage facility consisting of 200 MW of photovoltaic capacity and 100 MW of battery energy storage capacity located in Brazoria County.

Brattle is now developing cost estimates for these technologies. At the Supply Analysis Working Group (SAWG) meeting on March 22, 2024, Brattle and ERCOT invited stakeholder to provide comments on the reference technologies as well as the after-tax Weighted Average Cost of Capital (WACC), a key financial parameter for the CONE calculations (Attachment D). Brattle is compiling a summary and response document based on provided comments. The final calculated CONE values, an Excel spreadsheet model for CONE sensitivity analysis, and a draft CONE study report are expected to be filed by late April 2024. The final CONE study report is expected to be filed by end of May 2024.

Next Steps

ERCOT is seeking confirmation from the Commission on next steps in the reliability standard study. This delivery of the phase four scenarios completes the final modeling recommended by ERCOT at this time. To help the Commission interpret the analysis and begin to narrow the scope for stakeholder feedback, ERCOT has developed a white paper (included as Attachment A) with recommendations on certain input parameters. ERCOT representatives will be available at the April 11, 2024 Open Meeting to present this information and answer any questions that you may have regarding the reliability standard study phase four results, recommendations, and the CONE study update.

Respectfully submitted,

_*/s/ Woody Rickerson*___________
Woody Rickerson, P.E.
Vice President, System Planning and Weatherization

Reliability Standard: Potential Methodology for Interpreting the ERCOT Analysis

Background

Senate Bill 3 from the 88th Legislative Session required the Public Utility Commission of Texas (Commission or PUC) to ensure that ERCOT establishes requirements to meet the reliability needs of the power region. The Commission initiated PUC Project 54584 to establish a Reliability Standard for the ERCOT Region. The new standard would replace the 13.75% Reserve Margin previously approved by the ERCOT Board of Directors, which does not have a regulatory requirement to maintain.

Beginning in 2023 and after consultation with PUC Staff, ERCOT proposed a framework for this new Reliability Standard that was based on three criteria: Frequency, Magnitude, and Duration. Frequency is a measure of how often a loss-of-load (LOL) event occurs and is measured as an expected value (i.e., a probability-weighted average of LOL events over a given period for many Monte Carlo simulation outcomes). This frequency measure is called the Loss of Load Expectation, or LOLE. Magnitude considers the maximum hourly MW of all LOL events across many simulation outcomes, while Duration accounts for the maximum hours experienced for a single LOL event across the simulation outcomes.

ERCOT used the November 2022 Capacity and Demand Report (CDR) as the basis for the load and Resource information. The analysis focused on results for 2026 and used the Strategic Energy & Risk Valuation Model (SERVM) to perform a Monte Carlo probabilistic analysis of potential reliability outcomes based on a range of scenario variables. In total, ERCOT reported results for 76 different scenarios prior to the latest scenario set, referred to as Phase 4 scenarios. Each scenario and the corresponding results were based on 5,250 individual runs that capture a range of load, wind, solar, and thermal unit outage values.

In addition to the three reliability criteria proposed for the Reliability Standard, ERCOT used four secondary scenario variables to provide a larger set of unique scenarios:

Weatherization Effectiveness	Varied from 70% – 90% effectiveness at preventing weather-related thermal outages tied to low winter wind chill temperatures
Number of Historic Weather Years	42 weather years or a subset of the most recent 15 years
Retired Thermal Unit Capacity	Either 900 MW or 3300 MW
Type of New Units Added to Scenarios Requiring Additional Generation Beyond the 2026 Expected Portfolio	Gas combustion turbines (CTs) or a proportional mix of planned wind, gas, and battery storage capacity reflected in different CDR reports

The first of the secondary variables consisted of the effectiveness of new weatherization standards and the associated ERCOT inspection process in preventing weather-related Forced Outages on thermal units. The second variable considered the number of historic weather years used in the analysis. For the 5,250 Monte Carlo runs for each scenario, SERVM randomly selects one of the historic weather years. Each weather year is associated with hourly 2026 forecasted loads (based on the historical weather conditions) and intermittent renewable generation amounts, also based on historical weather conditions. ERCOT started the analysis with a 42-year weather set and also considered a smaller set comprising the most recent 15 weather years. Use of this smaller set puts larger weight on the more recent winter storm events. The analysis used a third variable to modify the number and type of units that would retire before 2026. Finally, a fourth variable considered the types of new generation that were added for some scenarios.

Altogether, the primary variables (Magnitude, Frequency, and Duration) along with the secondary variables (weatherization effectiveness, weather years, retirements, different combinations of new generation) resulted in 98 different scenarios.

In addition to the three primary criteria and four secondary variables, there are also several important scenario outcomes to consider in determining a new Reliability Standard. These are listed in the table below:

Summer and Winter Reserve Margins	Traditional Reserve Margin for the scenario during Summer Peak or Winter Peak provides a comparison to conditions ERCOT has traditionally seen.
Expected Unserved Energy (EUE)	EUE is the amount of energy (MWh) not served resulting from LOL events. Like LOLE, it is a probability-weighted average of amounts across all runs for a scenario. For a given hour, EUE is equivalent to the product of the Magnitude and Duration for that hour. It is a more common metric used in other markets and useful for comparisons.
Total System Cost (Market Cost + Customer Load Shed Damages + New Generation Fixed Cost)	Useful number that quantifies the annual ratepayer cost for electricity in ERCOT. It incorporates energy and Ancillary Services costs to serve load, customer load shed damage costs (EUE multiplied by the Value of Lost Load (VOLL)), and the fixed cost of new generation. (Note that for this analysis, the Market Cost is equivalent to the Customer Cost—the latter reflecting what ratepayers actually pay for electricity.)
Exceedance Probability for Duration and Magnitude	Exceedance Probability is the probability that a LOL event will exceed the maximum Duration or maximum Magnitude standards for any given scenario. A 3% Exceedance Probability indicates that 3 out of 100 LOL events will exceed either the maximum Magnitude or maximum Duration threshold.

MWs of Additional (New) Dispatchable Generation	This is a measure of additional generation capacity that must be added for the three primary criteria to be met. Additional information is also included in the analysis to examine the variable costs and market costs associated with the additional amounts of generation.

Methodology

What follows is a potential approach for parsing the 98 different scenarios. The methodology uses all the primary criteria as well as the secondary variables.

- **Magnitude** - In the fall of 2023, ERCOT surveyed the Transmission Service Providers (TSPs) responsible for administering rotating outages during a load shed event. An ERCOT Request for Information determined that the total load that is not critical or transmission-connected while reserving the 25% Under Frequency Load Shed (UFLS) is 31.7 GW at a 75 GW system load. Taking roughly 60% of the 31.7 GW provides an estimated amount of load (19 GW) that could be effectively rotated. A load shed amount exceeding 19 GW could result in some portion of the total required load shed amount not being rotated. This upper limit of 19 GW sets a boundary for considering how high the Magnitude variable can currently be set while maintaining rotation of all the outaged loads. Further investment in the distribution system or changes to the number or treatment of critical loads could raise the Magnitude variable to a value greater than 19 GW. This number will also change as new load is added to the system. The addition of future transmission-connected load is not included in the load shed plan.
- **Duration** - The Duration criteria is closely correlated to the Magnitude in the scenario results. When maximum Magnitude is restricted to values less than 19 GW, the maximum Duration results never exceed 14 hours. If you assume the Magnitude limitation of 19 GW allows all the load outaged during a LOL event to be rotated, 14 hours, even in a winter event, could be considered an acceptable LOL event duration. It is also relevant to remember that the ERCOT analysis of risk for the Reliability Standard indicates the LOL event risk is dominated by winter events.
- **Frequency** - For Frequency, a 1-in-5 value indicates that a LOL event is expected to occur once every five years. A Frequency of 1-in-20 would result in an expectation that a LOL event would occur once every 20 years. The lower the Frequency ratio the more often a LOL event is expected. If the Frequency of the LOL events are allowed to be as low as 1-in-5 years or 1-in-8 years, the resulting Magnitude exceeds the 19 GW Magnitude threshold when utilizing the 42-year weather set. Once the Frequency is set to 1-in-10, 15, or 20 years, approximately a third of the subset of scenario outcomes result in maximum Magnitude (19 GW) and maximum Duration (14 hour) values that meet the Magnitude and Duration criteria discussed previously. Historically, the LOLE frequency of 1-in-10 years has been a widely accepted industry standard.

ERCOT recommendation – *Maximum Magnitude should not exceed 19 GW, Frequency should be no more frequent than 1-in-10 years (e.g., 1-in-20 years), and the maximum Duration should not exceed 14 hours.*

The following is an examination of the four secondary variables and how their variability affects the overall results.

- **Weatherization Effectiveness** – ERCOT, based on field inspections of actual preparations, number of cure periods required, and a limited number of winter storm experiences (Winter Storms Elliot in 2022 and Mara in 2023), estimated that the weatherization effectiveness variable should be set at least as high as 85%. At the PUC Staff's request, the weatherization effectiveness variable was also tested at 70% and 90%. Using EUE as a measure, an increase of 1% in weatherization effectiveness resulted in an average 0.4% decrease in EUE. Using new CT capacity as a measure, a 1% increase in weatherization effectiveness resulted in an approximately 3% decrease in new CT capacity. Therefore, the overall effect of changing the measurement from 85% to 90% does not dramatically alter the overall results.

ERCOT's recommendation – *For studies supporting the Reliability Standard, the weatherization effectiveness should be set at 85% or 90% until metrics are available to make more precise effectiveness estimates.*

- **Number of Historic Weather Years** – ERCOT has access to 42 years of weather data along with power conversion models that account for temperature, wind speed, solar irradiance, and other variables. These probabilistic variables, along with probabilistic Forced Outage modeling, was the basis for SERVM simulations. ERCOT was also asked to consider only the most recent 15 years of weather data. This approach gave a heavier weighting to Winter Storm Uri making it like a 1-in-15-year storm. Most analysis agrees that, for Texas, Winter Storm Uri was closer to a 1-in-100-year storm. The move to a 15-year weather set instead of 42 years dramatically worsens reliability outcomes. For a Frequency of 1-in-10 years, the 15-year weather set resulted in a 25% increase in maximum LOL event durations, a 53% increase in maximum LOL event magnitudes, and a 188% increase in the amount of new dispatchable generation needed compared to the 42-year weather set.

ERCOT's recommendation–*Use at least the full 42 years of weather data for Reliability Standard studies.*

- **Number of Retirements** – ERCOT used both 900 MW and 3300 MW of retirements for the 2026 modeled year. The 900 MW figure came from facilities that have provided a public intent to retire. The 3300 MW number was based on an analysis that considered thermal units at risk of retirement by 2026 because of proposed Environmental Protection Agency (EPA) emission rules. The upcoming changes in the market structure, projected load growth, and existing and potential litigation over the EPA's proposed rules, make it difficult to predict the number of retirements that could eventually occur. The Commission could choose the lower of the two numbers and then track the MW amount of retirements that exceed 900 MW. The excess can be translated by ERCOT into additional amount of new generation.

ERCOT's recommendation – *Use the 900 MW retirement amount.*

- **Type of New Capacity** – The ERCOT analysis used several different combinations of new generation, including only CTs, the mix of new resource types found in the 2022 November CDR, and finally the mix of new Resource types found in the 2023 November CDR (which included proportionally more solar and batteries). The upcoming changes in the market design and new incentives make choosing a Resource mix difficult. It is likely that the mix of generation that is eventually built will not be what is currently in the interconnection queue. For establishing the Reliability Standard, it is simpler to use the CT assumption as a standard of comparison for all the scenarios. Subsequently, the amount of new CT generation can be translated into any mix of Resource types using average Effective Load Carrying Capability (ELCC) estimates and outage rate assumptions for dispatchable thermal resources.

ERCOT's recommendation *Use the combustion turbine as the Resource type for comparing scenarios.*

Final Results

ERCOT submitted an additional 22 scenarios as Phase 4 results. Phase 4 results use an 85% weatherization effectiveness factor, 900 MW of retirements, 42 years of historical weather, and incrementally add just CT generation to the December 2023 CDR's base resource portfolio.

The analysis includes all future generation capacity known at the time of the December 2023 CDR that is expected to be available by 2026. Hourly load is a probabilistic variable in SERVM, but the average summer peak value is 86 GW and the average winter peak value is 75 GW. Load that exceeds these average peak forecasts would require additional MWs of incremental capacity to maintain the equivalent scenario outcomes.

Using the Phase 4 results, if no additional generation (generation not included in the December 2023 CDR) is added, ERCOT would have a Reliability Standard with the following measurements. This scenario can be considered a baseline for comparison.

Incremental MWs Added	0 MW
Frequency	1-in-8.3 years
Duration	14 hours
Magnitude	25,652 MW

Adding 1,113 MW of new CT capacity produces the following results that fall just outside the suggested maximum Magnitude criterion. The analysis estimates a 98.57% chance the maximum Magnitude does not exceed 14,000 MW.

Incremental MWs Added		1,113 MW
Frequency		1-in-10 years
Duration		13 hours
Magnitude		22,375 MW

Adding 4,452 MW of new CT capacity produces the following results that are close to the suggested maximum Magnitude criterion. The Exceedance Probability should be considered when evaluating the Magnitude of 19,771 MW. The analysis estimates a 99.3% chance the maximum Magnitude does not exceed 14,000 MW.

Incremental MWs Added	4,452 MW
Frequency	1-in-15.7 years
Duration	13 hours
Magnitude	19,771 MW

Similarly, adding 5,936 MW of new CT capacity produces the following results that are close to the suggested maximum Magnitude criterion. The Exceedance Probability should be considered when evaluating the Magnitude of 19,164 MW. The analysis estimates a 99.64% chance the maximum Magnitude does not exceed 14,000 MW.

Incremental MWs Added	5,936 MW
Frequency	1-in-20.5 years
Duration	13 hours
Magnitude	19,614 MW

A scenario representing a more conservative Reliability Standard adds 8,904 MW of new CT capacity, producing the following results that all fall well within suggested parameters:

Incremental MWs Added	8,904 MW
Frequency	1-in-35.8 years
Duration	11 hours
Magnitude	16,124 MW

The complete data set results for the Phase 4 scenarios can provide more details on some of the key outcomes for each scenario.

Reliability Standard Study: System Cost Impact Analysis (Phase 4), Updated Phase 3 Simulation Results, and Technology Type Capacity Equivalencies

April 4, 2024

Modeling Study Design, Phase 4

Ran SERVM for a wider and more granular range of combustion turbine (CT) additions, using the 2026 resource portfolio from the December 2023 Capacity, Demand and Reserves (CDR) report and adding incremental CT capacity:

- 22 Monte Carlo simulations are reported for which no additional coal capacity is removed beyond the 900 MW scenario assumption
- Total CT capacity for the 22 simulations range from 0 to 20,776 MW (56 units @ 371 MW each)
- Range of expected frequencies (LOLEs) is 0.12 to 0 events/year; 0.12 is equivalent to a day with at least one LOL event every 8.3 years
- All simulations include 900 MW of unit retirements, 42 weather-years of hourly wind, solar and load data, and a weatherization success rate of 85% (i.e., 85% reduction in weather-related outages due to weatherization efforts)
- SERVM bug discovered and fixed by Astrape prior to Phase 4 study runs

Cost Analysis Approach

- Calculated the system (or societal) average cost, per year, for each resource portfolio; system cost is the sum of three cost components:
  - Market cost = Load x market price
  - Customer Load Shed Damages (Expected Unserved Energy x \$25,000/MWh Interim VOLL)
  - Fixed cost of incremental CT additions @ \$119,000/MW-year

– Calculated the incremental system cost needed to avoid a MWh of Expected Unserved Energy for each CT addition scenario

– Developed cost curves intended to help identify the expected frequency that minimizes system costs and meets maximum loss-of-load magnitude and duration criteria

– Evaluated the cost impact of adding sufficient CT capacity to avoid extreme market cost outcomes

Frequency, Magnitude and Duration Criteria

- Frequency:
  - The modeled system in 2026 is expected to yield a LOLE of close to 0.1 loss-of-load events per year (or one day with at least one loss-of-load event every 10 years).
  - This is in line with the industry LOLE standard and is therefore a reasonable benchmark with which to compare alternative values.
- Maximum Magnitude:
  - Based on TSP information, ERCOT estimates that a load shed amount exceeding 19 GW may not be capable of being fully rotated.
- Maximum Duration:
  - There are no ERCOT operational considerations that suggest a specific max duration criterion.
  - Assuming that all load can be shed on a rotating basis, a 14-hour maximum duration (which is the highest realized amount for the Phase 4 simulations) could be considered acceptable given improved customer lead-time communications since WS Uri.

Simulation Results Summary

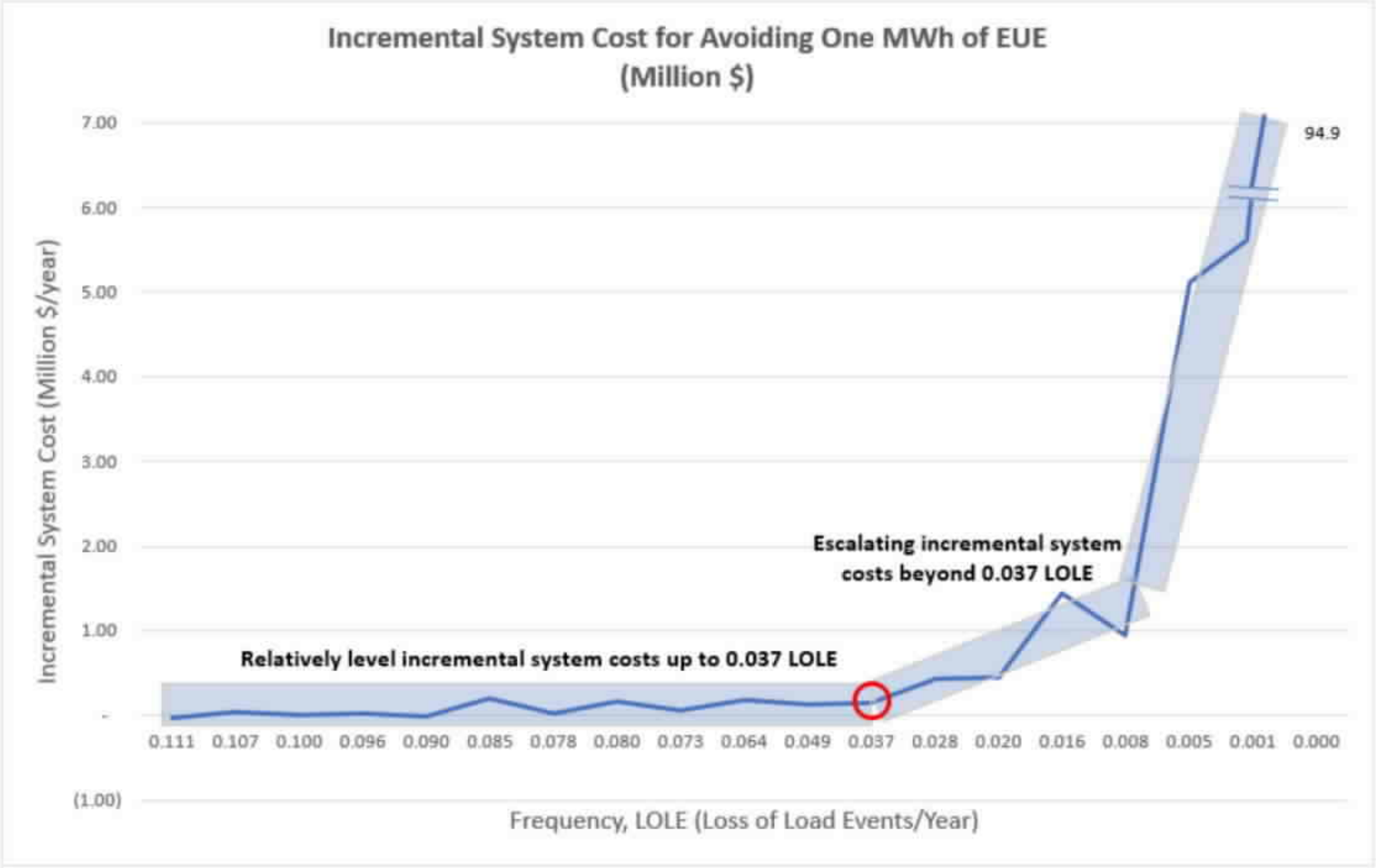
CTs Added	CT Capacity MW (Non-summer Rating)	Frequency (Expected Loss of Load Events/Year, LOLE)	Max Magnitude (MW/hr)	Max Duration (Hrs)	EUE (MWh)	System Cost (Million $/Year)
0	-	0.120	25,652	14	4,213.6	12,264.71
1	371	0.111	22,901	14	3,825.6	12,250.39
2	742	0.107	24,566	14	3,672.8	12,256.09
3	1,113	0.100	22,375	13	3,331.1	12,259.85
4	1,484	0.096	21,669	13	3,075.2	12,264.68
5	1,855	0.090	22,388	13	2,743.9	12,263.77
6	2,226	0.085	22,176	13	2,637.8	12,285.76
7	2,597	0.078	22,013	13	2,418.3	12,290.71
8	2,968	0.080	21,028	14	2,263.2	12,316.17
9	3,339	0.073	21,583	13	2,073.8	12,327.72
12	4,452	0.064	19,771	13	1,744.9	12,387.93
16	5,936	0.049	19,614	13	1,222.9	12,459.16
20	7,420	0.037	18,674	12	731.9	12,535.27
24	8,904	0.028	16,124	11	500.1	12,634.39
28	10,388	0.020	13,418	10	279.2	12,735.21
32	11,872	0.016	12,807	10	188.8	12,865.08
36	13,356	0.008	12,666	9	60.5	12,986.74
40	14,840	0.005	7,903	8	31.1	13,137.44
44	16,324	0.001	5,085	3	3.6	13,293.08
48	17,808	0.000	5,097	3	1.9	13,458.18
52	19,292	0.000	0	0	-	13,628.20
56	20,776	0.000	0	0	-	13,797.07

CT addition scenarios start at the LOLE level (0.12) where no portfolio capacity needs to be removed or added.

Key Takeaways:

- **A 0.1 expected frequency (LOLE) is not sufficient to constrain the max magnitude to 19 GW; a LOLE of approximately 0.04 is needed to achieve that. The incremental system cost to achieve this increased reliability is between $195 and $271 million per year above the amount that supports a 0.1 LOLE.**
- **A 0.02 LOLE would be needed to reduce the max duration to 10 hours. This lower frequency increases the annual system cost by $471 million above the amount that supports an approximate 0.1 LOLE.**

Incremental System Cost for Avoiding one MWh of Expected Unserved Energy (EUE)

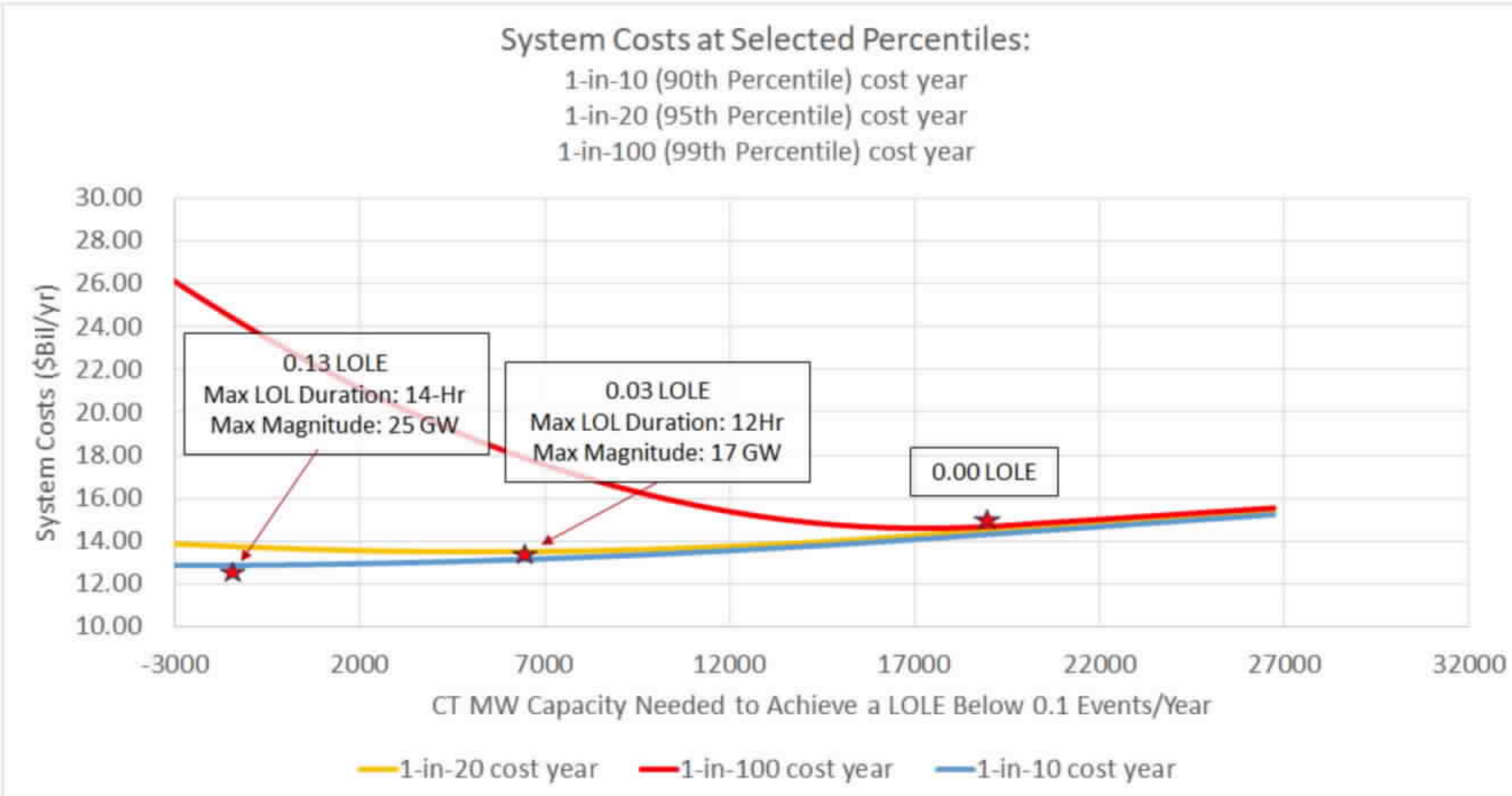


Key Takeaway: Incremental system costs for avoiding a MWh of EUE start escalating as expected loss-of-load frequency (LOLE) goes below ~0.04 events/year.

Comparison of High System Cost Years

- Market costs are highly variable from year to year; the SERVM runs reflect average costs across all simulation outcomes.
- How much additional CT capacity would be needed to fully hedge against a year with higher-than-average system costs?
- For a "1-in-100" weather year, system costs would be lowest with CT additions sufficient to yield a zero LOLE:
  - Requires ~17.1 GW of additional capacity above that needed for a 0.1 LOLE
  - Expected annual cost, in addition to the cost to get to 0.1 LOLE, is $2.03b
- For a 1-in-20 weather year, system costs would be lowest with CT additions sufficient to yield a 0.03 LOLE:
  - Requires ~5.2 GW additional capacity above that needed for a 0.1 LOLE
  - Expected annual cost, in addition to the cost to get to 0.1 LOLE, is $618m
- For a 1-in-10 weather year, system costs would be lowest with CT additions sufficient to yield a 0.16 LOLE:
  - Expected cost is less than a portfolio designed to achieve 0.1 LOLE ($441m annual savings)
  - However, reliability criteria suggested on Slide 4 will not be met with this LOLE level.

Comparison of Years with High System Costs



Updated Phase 3 Simulation Results

- SERVM bug discovered and fixed by Astrape prior to Phase 4 study runs; the bug affected battery scheduling and resulted in erroneous negative market prices during negative net load hours.
- Impacts of the bug:
  - Solar over-curtailment and depressed market costs
  - Battery storage scheduling was sub-optimal
- Re-ran all 76 Phase 3 scenario simulations; the main impacts include:
  - Substantial increase in market costs, on the order of $3 to 4 billion
  - For most of the resource portfolios, an increase in reliability; for example, across the Base Case portfolios, EUE decreased, on average, by ~10%, while Max Magnitude decreased, on average, by ~850 MW.
- Phase 1 simulations were not re-run because that modeling was an exploratory effort.
- Phase 2 simulations were not re-run because many portfolio scenarios are replicated in the Phase 3 and 4 simulations, while other scenarios were dropped for further consideration (e.g., 3,300 MW retirement scenario).

CT vs. Wind/Solar Capacity Equivalencies

- The following table shows how much solar, wind, and standalone battery storage capacity is needed to displace the CT capacities used in the SERVM simulations assuming a system that meets a 0.1 events/year LOLE. The solar and wind capacity conversions are based on Effective Load Carrying Capabilities (ELCCs) published in ERCOT's 2022 ELCC study.
- The ELCCs are based on a reference combustion turbine with perfect reliability, so the wind, solar, and battery storage capacities are grossed down by 1.98% to reflect the assumed CT effective forced outage rate (EFOR) used in the reliability study modeling.

	Megawatts (MW)					
CTs Added [1]	Combustion Turbine Maximum Capacity [2]	Equivalent West Solar, Summer [3]	Equivalent Non-West Solar, Summer [4]	Equivalent Wind, Summer [5]	Equivalent Wind, Winter [6]	Equivalent 2-hour Battery [7]
1	371	1,081	1,351	2,226	1,991	430
2	742	2,162	2,702	4,451	3,983	860
3	1,113	3,243	4,054	6,677	5,974	1,290
4	1,484	4,324	5,405	8,902	7,965	1,720
5	1,855	5,405	6,756	11,128	9,956	2,150
6	2,226	6,486	8,107	13,353	11,948	2,580
7	2,597	7,567	9,459	15,579	13,939	3,010
8	2,968	8,648	10,810	17,805	15,930	3,440
9	3,339	9,729	12,161	20,030	17,922	3,869
12	4,452	12,972	16,215	26,707	23,896	5,159
16	5,936	17,296	21,620	35,609	31,861	6,879
20	7,420	21,620	27,025	44,511	39,826	8,599
24	8,904	25,944	32,430	53,414	47,791	10,319
28	10,388	30,268	37,835	62,316	55,756	12,038
32	11,872	34,592	43,240	71,218	63,721	13,758
36	13,356	38,916	48,644	80,120	71,687	15,478
40	14,840	43,240	54,049	89,023	79,652	17,198
44	16,324	47,563	59,454	97,925	87,617	18,917
48	17,808	51,887	64,859	106,827	95,582	20,637
52	19,292	56,211	70,264	115,729	103,547	22,357
56	20,776	60,535	75,669	124,632	111,512	24,077

Table 1. Base Case

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	Coal Capacity Reduction (MW)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 5	900	100% CT	12%	16%	6,028	30	365	0	0	15,239	15,209	15,209	15,239	12,013	12,343	15	0.02%	4.15%	4.51%	25,982	2.10%	4.65%	9.07%	—	
2	1 in 8	900	100% CT	16%	19%	3,381	18	0	1,855	221	15,139	15,110	15,331	15,349	12,104	12,342	15	0.02%	3.12%	3.55%	23,194	1.33%	2.79%	5.73%	90,211	49,967
3	1 in 10	900	100% CT	17%	22%	2,470	13	0	3,335	397	15,117	15,104	15,501	15,514	12,404	12,815	14	0.00%	2.83%	3.03%	23,117	0.97%	2.21%	4.46%	155,750	188,334
4	1 in 15	900	100% CT	21%	27%	1,388	7	0	6,670	795	15,093	15,086	15,880	15,887	12,162	12,944	13	0.00%	1.59%	1.54%	18,557	0.25%	1.12%	2.53%	303,154	291,414
5	1 in 20	900	100% CT	23%	30%	708	4	0	8,533	1,015	15,086	15,085	16,100	16,100	12,051	13,070	12	0.00%	0.88%	1.05%	14,869	0.04%	0.48%	1.83%	367,649	361,573
6	1 in 5	900	CDR Mix	12%	16%	6,948	35	2,700	0	0	15,201	15,166	15,166	15,200	12,009	12,344	15	0.02%	4.33%	5.24%	26,489	2.84%	5.08%	13.48%	—	
7	1 in 8	900	CDR Mix	16%	20%	4,255	21	0	742	88	15,104	15,083	15,171	15,192	12,161	12,602	15	0.02%	3.53%	3.79%	24,153	1.68%	3.39%	6.77%	32,754	2,055
8	1 in 10	900	CDR Mix	17%	22%	3,174	16	0	2,226	265	15,128	15,112	15,377	15,343	12,435	12,716	15	0.02%	2.83%	3.01%	22,357	1.28%	2.55%	5.35%	103,331	144,441
9	1 in 15	900	CDR Mix	21%	27%	1,512	8	0	5,565	662	15,056	15,049	15,711	15,719	12,230	12,900	13	0.00%	1.26%	1.75%	17,819	0.33%	1.30%	2.88%	235,131	231,046
10	1 in 20	900	CDR Mix	23%	30%	857	4	0	7,420	883	15,043	15,030	15,926	15,931	12,117	13,004	12	0.00%	0.67%	1.10%	20,275	0.12%	0.79%	2.00%	308,587	345,795
11	1 in 5	3,300	100% CT	12%	17%	5,714	29	0	1,484	177	15,187	15,158	15,335	15,364	12,065	13,170	15	0.02%	4.04%	4.32%	24,502	2.00%	4.50%	8.69%	—	
12	1 in 8	3,300	100% CT	13%	20%	3,711	19	0	3,710	441	15,146	15,127	15,569	15,587	12,612	13,172	15	0.02%	3.34%	3.41%	23,859	1.31%	3.03%	6.17%	132,298	116,720
13	1 in 10	3,300	100% CT	17%	22%	2,518	13	0	5,563	662	15,128	15,116	15,778	15,790	12,414	13,080	15	0.02%	2.36%	2.33%	21,066	0.86%	1.99%	4.33%	185,034	175,262
14	1 in 15	3,300	100% CT	21%	27%	1,308	7	0	8,533	1,015	15,113	15,107	16,122	16,129	12,178	13,200	14	0.00%	1.10%	1.40%	16,648	0.25%	1.12%	2.17%	291,881	286,480
15	1 in 20	3,300	100% CT	22%	29%	507	3	0	10,017	1,193	15,108	15,104	16,298	16,300	12,084	13,281	12	0.00%	0.53%	1.23%	16,008	0.11%	0.76%	2.23%	440,289	433,338
16	1 in 5	3,300	CDR Mix	12%	16%	7,317	37	-400	0	0	15,169	15,133	15,133	15,169	12,582	13,019	16	0.04%	4.88%	5.30%	27,548	2.33%	5.34%	10.89%	—	
17	1 in 8	3,300	CDR Mix	16%	20%	4,063	20	0	2,968	353	15,172	15,152	15,455	15,475	12,640	13,518	15	0.02%	3.37%	3.50%	22,554	1.69%	3.26%	6.32%	108,512	99,079
18	1 in 10	3,300	CDR Mix	18%	23%	2,804	14	0	4,823	574	15,089	15,075	15,649	15,663	12,439	13,047	14	0.00%	2.42%	2.83%	24,051	0.93%	2.30%	4.93%	179,643	158,019
19	1 in 15	3,300	CDR Mix	21%	28%	1,303	7	0	8,162	971	15,071	15,064	16,035	16,042	12,295	13,344	13	0.00%	1.34%	1.49%	17,937	0.34%	1.18%	2.80%	268,433	265,925
20	1 in 20	3,300	CDR Mix	23%	30%	901	5	0	9,646	1,148	15,063	15,060	16,208	16,213	12,118	13,271	13	0.00%	0.80%	1.10%	16,856	0.19%	0.77%	2.04%	390,648	382,257

Table 2. Fifteen Weather Years Sensitivity

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	19%	23%	4,210	21	3,363	402	15,152	15,131	15,533	15,554	12,649	13,137	13	0.02%	4.39%	5.17%	20,610	1.07%	3.79%	6.29%	—	
2	1 in 10	900	100% CT	22%	26%	2,399	12	8,162	971	15,136	15,124	16,095	16,107	12,290	13,259	13	0.00%	2.61%	3.04%	17,966	0.27%	1.71%	4.80%	164,673	161,255
3	1 in 15	900	100% CT	26%	31%	532	3	11,877	1,413	15,121	15,118	16,531	16,534	12,014	13,430	11	0.00%	0.64%	0.80%	12,202	0.00%	0.43%	2.19%	252,735	249,082
4	1 in 20	900	100% CT	28%	33%	357	2	13,356	1,589	15,117	15,113	16,703	16,707	11,906	13,498	11	0.00%	0.27%	0.33%	9,256	0.00%	0.00%	1.32%	751,357	741,230
5	1 in 8	900	CDR Mix	20%	24%	4,097	20	3,363	402	15,115	15,095	15,757	15,778	12,429	13,112	13	0.00%	3.79%	4.43%	21,407	1.39%	3.63%	5.89%	—	
6	1 in 10	900	CDR Mix	24%	29%	2,070	10	8,533	1,015	15,099	15,089	16,104	16,115	12,240	13,266	13	0.00%	1.60%	2.88%	16,094	0.10%	1.32%	4.37%	174,234	171,163
7	1 in 15	900	CDR Mix	27%	32%	728	4	11,130	1,324	15,086	15,083	16,407	16,411	12,047	13,370	11	0.00%	0.32%	1.07%	13,504	0.00%	0.17%	2.67%	230,272	225,690
8	1 in 20	900	CDR Mix	28%	34%	402	2	13,614	1,621	15,083	15,081	16,382	16,366	11,908	13,489	11	0.00%	0.11%	0.37%	12,880	0.00%	0.27%	1.93%	343,695	337,436
9	1 in 8	3,300	100% CT	20%	24%	3,431	17	8,533	1,015	15,163	15,146	16,161	16,178	12,388	13,410	13	0.00%	3.73%	4.37%	18,058	0.04%	2.03%	5.71%	—	
10	1 in 10	3,300	100% CT	23%	27%	1,663	8	11,130	1,324	15,149	15,141	16,466	16,474	12,224	13,550	12	0.00%	1.81%	2.24%	17,620	0.21%	1.23%	4.11%	174,613	172,123
11	1 in 15	3,300	100% CT	26%	31%	372	2	14,098	1,678	15,139	15,136	16,814	16,816	12,012	13,693	11	0.00%	0.27%	0.43%	12,038	0.00%	0.21%	2.45%	324,266	319,446
12	1 in 20	3,300	100% CT	27%	32%	319	2	14,840	1,766	15,138	15,133	16,901	16,904	11,988	13,757	11	0.00%	0.37%	0.48%	12,101	0.00%	0.43%	2.40%	1,665,133	1,658,165
13	1 in 8	3,300	CDR Mix	21%	28%	3,452	17	8,162	971	15,127	15,110	16,081	16,098	12,403	13,392	13	0.00%	2.99%	4.12%	18,470	0.35%	3.25%	5.76%	—	
14	1 in 10	3,300	CDR Mix	23%	27%	2,175	11	10,017	1,192	15,116	15,105	16,297	16,308	12,272	13,475	13	0.00%	1.81%	2.88%	17,154	0.32%	2.08%	4.80%	171,486	168,092
15	1 in 15	3,300	CDR Mix	26%	31%	906	5	12,614	1,501	15,105	15,101	16,602	16,606	12,111	13,617	11	0.00%	0.32%	1.12%	14,379	0.11%	0.37%	3.20%	243,598	239,868
16	1 in 20	3,300	CDR Mix	28%	33%	418	2	14,469	1,722	15,100	15,098	16,819	16,822	11,598	13,710	11	0.00%	0.16%	0.48%	10,154	0.00%	0.11%	2.08%	433,552	446,563

Table 3. "Increased IBR" Portfolio Sensitivity

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: Increased Planned Wind, Solar, ESR proportional to May 2023 CDR	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	CDR Mix + Inc IBR	18%	18%	4,310	23	0	0	14,818	14,796	14,796	14,818	11,524	11,546	15	0.02%	3.49%	3.34%	21,320	1.30%	3.68%	6.30%	—	
2	1 in 10	900	CDR Mix + Inc IBR	20%	22%	3,634	18	0	0	14,320	14,302	14,302	14,320	10,798	10,816	15	0.00%	2.63%	3.49%	23,195	1.47%	3.16%	5.71%	0	(156,423)
3	1 in 15	900	CDR Mix + Inc IBR	40%	31%	2,089	10	0	0	13,464	13,434	13,434	13,464	9,396	9,606	11	0.00%	0.42%	2.44%	20,377	0.80%	2.08%	4.29%	0	(147,863)
4	1 in 20	900	CDR Mix + Inc IBR	34%	33%	1,634	8	0	0	13,213	13,205	13,205	13,213	9,246	9,254	11	0.00%	0.11%	2.15%	17,881	0.30%	1.18%	3.41%	0	(151,357)
5	1 in 8	3,300	CDR Mix + Inc IBR	27%	21%	4,866	24	0	0	14,128	14,104	14,104	14,128	10,578	10,602	13	0.00%	2.99%	4.17%	24,804	2.10%	4.29%	7.37%	—	
6	1 in 10	3,300	CDR Mix + Inc IBR	37%	28%	3,815	19	0	0	13,655	13,636	13,636	13,655	9,990	10,009	12	0.00%	1.67%	3.68%	25,231	1.32%	3.60%	6.08%	0	(407,863)
7	1 in 15	3,300	CDR Mix + Inc IBR	57%	35%	2,360	12	0	0	13,050	13,038	13,038	13,050	9,370	9,382	11	0.00%	0.11%	2.67%	15,988	0.37%	2.63%	4.30%	0	(417,367)
8	1 in 20	3,300	CDR Mix + Inc IBR	67%	40%	1,600	8	0	0	12,793	12,786	12,786	12,793	8,648	8,656	10	0.00%	0.00%	2.08%	20,362	0.69%	1.77%	3.37%	0	(339,643)

Table 4. 70% Weatherization Effectiveness Sensitivity

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	17%	20%	4,234	21	3,710	441	15,130	15,109	15,551	15,572	12,489	13,552	15	0.02%	3.37%	3.75%	27,064	1.49%	3.30%	6.79%	—	
2	1 in 10	900	100% CT	19%	22%	3,124	16	5,194	618	15,117	15,101	15,719	15,735	12,358	12,997	15	0.02%	2.84%	3.05%	22,480	1.12%	2.47%	5.50%	135,095	131,645
3	1 in 15	900	100% CT	24%	28%	1,257	6	9,646	1,148	15,096	15,089	16,237	16,243	12,050	13,204	13	0.00%	1.16%	1.33%	20,557	0.36%	0.93%	2.63%	276,321	270,299
4	1 in 20	900	100% CT	23%	30%	834	4	11,130	1,324	15,091	15,087	16,412	16,416	11,335	13,305	13	0.00%	0.82%	1.23%	16,161	0.11%	0.80%	2.05%	305,845	494,463
5	1 in 8	900	CDR Mix	17%	21%	4,789	24	2,968	353	15,103	15,079	15,432	15,456	12,531	13,908	14	0.00%	3.52%	4.19%	23,683	2.00%	3.96%	7.43%	—	
6	1 in 10	900	CDR Mix	19%	23%	3,595	18	4,452	530	15,087	15,069	15,599	15,617	12,401	12,949	14	0.00%	3.03%	3.41%	23,028	1.31%	3.12%	5.88%	147,979	135,701
7	1 in 15	900	CDR Mix	24%	29%	1,338	7	8,904	1,060	15,062	15,056	16,115	16,122	12,053	13,138	13	0.00%	1.10%	1.49%	20,101	0.46%	1.22%	2.84%	234,601	228,947
8	1 in 20	900	CDR Mix	23%	30%	1,158	6	9,646	1,148	15,060	15,054	16,202	16,208	12,054	13,208	13	0.00%	1.00%	1.08%	17,532	0.29%	1.05%	2.46%	491,230	482,031
9	1 in 8	3,300	100% CT	17%	20%	4,065	20	5,936	706	15,147	15,127	15,839	15,869	12,488	13,211	15	0.02%	3.37%	3.70%	23,216	1.47%	3.45%	6.39%	—	
10	1 in 10	3,300	100% CT	19%	22%	2,999	15	7,420	883	15,132	15,117	16,000	16,015	12,341	13,735	15	0.02%	2.79%	3.07%	23,160	1.03%	2.34%	5.24%	163,534	161,015
11	1 in 15	3,300	100% CT	24%	28%	1,119	6	11,872	1,413	15,113	15,107	16,520	16,525	12,030	13,468	13	0.00%	1.16%	1.37%	15,000	0.28%	1.03%	2.39%	281,886	276,493
12	1 in 20	3,300	100% CT	25%	30%	705	4	13,356	1,589	15,109	15,105	16,695	16,698	11,971	13,564	12	0.00%	0.77%	0.88%	15,714	0.06%	0.65%	1.93%	426,195	421,508
13	1 in 8	3,300	CDR Mix	17%	21%	4,286	21	5,194	618	15,111	15,090	15,708	15,729	12,524	13,144	15	0.02%	3.11%	3.73%	24,660	1.90%	3.38%	6.91%	—	
14	1 in 10	3,300	CDR Mix	19%	23%	3,388	17	6,678	795	15,102	15,085	15,879	15,896	12,394	13,306	15	0.02%	2.51%	3.28%	24,553	1.49%	2.57%	5.58%	195,671	191,069
15	1 in 15	3,300	CDR Mix	22%	27%	1,787	9	9,646	1,148	15,084	15,075	16,223	16,232	12,174	13,331	14	0.00%	1.68%	2.21%	19,469	0.60%	1.57%	3.54%	229,652	214,849
16	1 in 20	3,300	CDR Mix	23%	30%	933	5	11,872	1,413	15,076	15,071	16,484	16,489	12,058	13,490	13	0.00%	0.70%	1.20%	18,403	0.28%	0.30%	2.33%	317,641	313,133

Table 5. 90% Weatherization Effectiveness Sensitivity

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	14%	17%	3,341	17	1,113	132	15,136	15,119	15,252	15,269	12,340	13,089	15	0.02%	2.99%	3.22%	23,511	1.12%	2.38%	3.77%	—	
2	1 in 10	900	100% CT	15%	18%	2,811	14	2,226	265	15,119	15,105	15,370	15,384	12,441	12,720	15	0.02%	2.53%	2.77%	23,642	0.82%	2.00%	4.80%	245,948	222,996
3	1 in 15	900	100% CT	19%	22%	1,490	7	5,194	618	15,092	15,085	15,703	15,711	12,315	12,895	13	0.00%	1.58%	1.79%	19,220	0.33%	1.27%	2.77%	267,438	253,951
4	1 in 20	900	100% CT	20%	24%	992	5	6,678	795	15,085	15,080	15,875	15,880	12,100	12,906	12	0.00%	1.00%	1.34%	15,409	0.13%	0.82%	2.08%	334,726	344,711
5	1 in 8	900	CDR Mix	14%	17%	3,935	20	0	0	15,115	15,095	15,096	15,115	12,595	12,591	15	0.02%	3.26%	3.45%	23,778	1.32%	3.08%	6.45%	—	
6	1 in 10	900	CDR Mix	15%	18%	3,209	16	1,113	132	15,091	15,075	15,207	15,223	12,471	12,613	14	0.00%	2.91%	3.28%	21,863	1.28%	2.69%	5.39%	182,300	133,357
7	1 in 15	900	CDR Mix	19%	23%	1,636	8	4,452	530	15,054	15,046	15,576	15,584	12,344	12,782	13	0.00%	1.37%	1.81%	19,263	0.42%	1.33%	2.30%	252,605	234,171
8	1 in 20	900	CDR Mix	22%	26%	904	5	6,678	795	15,042	15,038	15,833	15,837	12,103	12,902	12	0.00%	0.82%	1.16%	16,034	0.17%	0.74%	1.90%	362,234	351,196
9	1 in 8	3,300	100% CT	14%	16%	3,603	18	2,968	353	15,143	15,125	15,479	15,496	12,619	12,984	15	0.02%	3.12%	3.59%	22,120	1.19%	2.63%	5.89%	—	
10	1 in 10	3,300	100% CT	15%	18%	2,688	13	4,452	530	15,127	15,113	15,643	15,656	12,433	12,998	14	0.00%	2.40%	2.70%	20,045	0.55%	2.19%	4.59%	192,613	179,672
11	1 in 15	3,300	100% CT	19%	22%	1,300	7	7,420	883	15,108	15,101	15,984	15,991	12,198	12,988	14	0.00%	1.49%	1.08%	18,699	0.23%	1.16%	2.69%	263,871	258,342
12	1 in 20	3,300	100% CT	20%	24%	1,008	5	8,904	1,060	15,102	15,097	16,157	16,162	12,102	13,166	12	0.00%	1.09%	1.22%	15,166	0.11%	0.90%	1.94%	301,829	490,517
13	1 in 8	3,300	CDR Mix	14%	17%	3,935	20	2,226	265	15,107	15,087	15,352	15,371	12,557	12,882	14	0.00%	3.28%	3.40%	23,635	1.39%	3.20%	6.29%	—	
14	1 in 10	3,300	CDR Mix	16%	19%	2,855	14	3,710	441	15,089	15,074	15,516	15,530	12,467	12,515	14	0.00%	2.70%	2.97%	24,141	1.03%	2.21%	4.09%	160,007	148,831
15	1 in 15	3,300	CDR Mix	19%	23%	1,542	8	6,678	795	15,068	15,060	15,855	15,863	12,237	13,040	13	0.00%	1.59%	1.77%	17,034	0.58%	1.16%	2.80%	268,922	258,200
16	1 in 20	3,300	CDR Mix	21%	26%	843	4	8,904	1,060	15,058	15,054	16,114	16,118	12,098	13,161	12	0.00%	0.70%	1.00%	13,328	0.19%	0.84%	1.79%	380,414	371,273

Table 6. Phase 4 Scenario

No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: Dec. 2023 CDR + CTs	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL ($5,000/MWh) (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	SYSTEM COST Market Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8.3	900	Dec. 2023 CDR Mix	20%	21%	4,214	105	0	0	14,353	14,333	14,333	14,437	12,159	12,265	14	0.00%	3.09%	3.18%	25,612	1.79%	3.30%	6.28%	—	—
2	1 in 9.0	900	Dec. 2023 CDR Mix	21%	21%	3,826	96	371	44	14,343	14,324	14,368	14,463	12,111	12,250	14	0.00%	2.84%	3.30%	23,901	1.50%	3.16%	5.79%	113,775	93,164
3	1 in 9.4	900	Dec. 2023 CDR Mix	21%	22%	3,673	92	742	88	14,335	14,310	14,404	14,490	12,036	12,216	14	0.00%	2.87%	3.43%	24,366	1.64%	3.09%	5.40%	288,808	235,777
4	1 in 10.0	900	Dec. 2023 CDR Mix	22%	22%	3,331	83	1,113	132	14,327	14,310	14,443	14,526	12,044	12,260	13	0.00%	2.53%	3.10%	22,371	1.43%	2.61%	5.07%	125,229	111,743
5	1 in 10.4	900	Dec. 2023 CDR Mix	22%	23%	3,075	77	1,484	177	14,310	14,303	14,480	14,558	12,011	12,265	13	0.00%	2.23%	3.10%	21,669	1.35%	2.40%	4.93%	171,479	130,557
6	1 in 11.1	900	Dec. 2023 CDR Mix	23%	23%	2,744	69	1,855	221	14,313	14,306	14,520	14,589	11,974	12,264	13	0.00%	2.07%	2.76%	23,388	1.31%	2.34%	4.53%	193,274	118,144
7	1 in 11.8	900	Dec. 2023 CDR Mix	23%	24%	2,638	66	2,226	265	14,308	14,293	14,560	14,626	11,935	12,266	13	0.00%	1.89%	2.72%	22,195	1.34%	2.13%	4.34%	416,034	175,348
8	1 in 12.4	900	Dec. 2023 CDR Mix	24%	25%	2,263	57	2,968	353	14,301	14,293	14,643	14,699	11,900	12,310	14	0.00%	1.54%	2.51%	21,078	0.78%	1.89%	4.13%	235,725	225,801
9	1 in 12.8	900	Dec. 2023 CDR Mix	23%	25%	2,418	60	2,597	309	14,304	14,292	14,601	14,662	11,921	12,291	13	0.00%	1.86%	2.37%	22,013	1.01%	1.90%	4.13%	284,680	269,659
10	1 in 13.7	900	Dec. 2023 CDR Mix	24%	26%	2,074	52	3,339	397	14,297	14,288	14,684	14,735	11,870	12,320	13	0.00%	1.32%	2.36%	21,383	0.88%	1.81%	3.50%	256,296	239,434
11	1 in 15.7	900	Dec. 2023 CDR Mix	25%	27%	1,745	44	4,452	530	14,290	14,285	14,811	14,854	11,811	12,388	13	0.00%	0.97%	2.08%	19,771	0.70%	1.62%	3.17%	402,789	396,751
12	1 in 20.3	900	Dec. 2023 CDR Mix	27%	29%	1,223	31	5,936	706	14,285	14,275	14,982	15,013	11,722	12,459	13	0.00%	0.63%	1.22%	19,614	0.36%	1.18%	2.30%	338,255	329,107
13	1 in 27.0	900	Dec. 2023 CDR Mix	29%	31%	732	18	7,420	883	14,279	14,274	15,157	15,175	11,636	12,535	12	0.00%	0.29%	1.03%	18,674	0.17%	0.78%	1.83%	355,706	354,756
14	1 in 55.8	900	Dec. 2023 CDR Mix	30%	33%	500	13	8,904	1,060	14,275	14,271	15,332	15,345	11,502	12,634	11	0.00%	0.15%	0.86%	16,124	0.10%	0.48%	1.49%	751,795	735,595
15	1 in 88.9	900	Dec. 2023 CDR Mix	32%	35%	279	7	10,388	1,236	14,273	14,272	15,508	15,515	11,493	12,736	10	0.00%	0.00%	0.32%	13,418	0.00%	0.11%	1.18%	795,332	794,750
16	1 in 62.0	900	Dec. 2023 CDR Mix	34%	37%	189	5	11,872	1,413	14,273	14,272	15,686	15,689	11,448	12,865	10	0.00%	0.00%	0.23%	12,807	0.00%	0.13%	0.93%	1,553,277	1,552,856
17	1 in 117.9	900	Dec. 2023 CDR Mix	36%	39%	61	2	13,356	1,589	14,272	14,271	15,861	15,863	11,398	12,987	9	0.00%	0.00%	0.11%	12,666	0.00%	0.04%	0.38%	1,577,004	1,577,798
18	1 in 189.6	900	Dec. 2023 CDR Mix	37%	41%	31	1	14,840	1,766	14,272	14,271	16,038	16,038	11,371	13,137	8	0.00%	0.00%	0.04%	7,903	0.00%	0.00%	0.21%	5,096,875	5,391,010
19	1 in 791.1	900	Dec. 2023 CDR Mix	39%	43%	4	0	16,324	1,943	14,271	14,271	16,214	16,214	11,333	13,293	3	0.00%	0.00%	0.03%	3,088	0.00%	0.00%	0.04%	6,435,238	6,471,631
20	1 in 21,953	900	Dec. 2023 CDR Mix	41%	45%	1	0	17,800	2,119	14,271	14,271	16,390	16,390	11,339	13,458	3	0.00%	0.00%	0.00%	1,077	0.00%	0.00%	0.04%	101,553,421	101,548,907
21	1 in infinity	900	Dec. 2023 CDR Mix	42%	48%	0	0	19,292	2,296	14,271	14,271	16,567	16,567	11,332	13,628	3	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%	94,802,170	94,701,815
22	1 in infinity	900	Dec. 2023 CDR Mix	44%	50%	0	0	20,376	2,420	14,271	14,271	16,744	16,744	11,335	13,757	3	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%	—	—

* Reserve margins are calculated with Effective Load Carrying Capabilities for wind, solar, battery storage, and non-PUN thermal resources.

** Market Costs: The sum of wholesale energy costs attributable to serving load, plus Ancillary Service costs. Market Cost is calculated outside the model using the following model metrics: Market Cost = 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.

Cost Parameters

VOLL ($/MWh)	$	5,000.00
CONE ($/MW-year)	$	119,000.00
Interim VOLL ($/MW	$	25,000.00

The tables below [illegible]

[illegible]

Section 1: Base Case

900 MW Retirement Scenario												
	Initial Portfolio		BWS/CT Scenario					CDE Mix				
Resource Type	Dec 2022 CDM	Portfolio after Retiring 900 MW of Gas Capacity	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	13,650	13,650	(650)					(2,700)				
Gas	[illegible]	[illegible]										
Wind	[illegible]	[illegible]										
Solar	22,775	22,775						782	782	782	782	782
Battery Storage	11,945	11,945						7,082	7,082	7,082	3,082	3,082
New CTs	-	-		[illegible]	[illegible]	[illegible]	[illegible]	-	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

3,000 MW Retirement Scenario												
	Initial Portfolio		BWS/CT Scenario					CDE Mix				
Resource Type	Dec 2022 CDM	Portfolio after Retiring 1,000 MW of Gas/2,000 MW Coal	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	13,650	11,650						(400)				
Gas	[illegible]	[illegible]										
Wind	21,857	21,857	-		-	-	-	-		-	-	-
Solar	22,775	22,775	-		-	-	-	782	782	782	782	782
Battery Storage	11,946	11,946						(608)	(608)	(608)	3,082	3,082
New CTs	-	-	1,957	[illegible]	5,975	8,577	17,017	-	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

Section 2: Fifteen Weather Years Sensitivity

900 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					7,082	3,082	3,082	7,082
New CTs	5,566	[illegible]	11,874	[illegible]	5,566	[illegible]	11,150	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

3,000 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					7,082	3,082	3,082	7,082
New CTs	8,700	11,170	17,098	[illegible]	8,167	17,017	17,674	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Section 3: [illegible] Sensitivity

900 MW Retirement Scenario				
	CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal				
Gas				
Wind	[illegible]	2,460	[illegible]	[illegible]
Solar	[illegible]	[illegible]	[illegible]	[illegible]
Battery Storage	[illegible]	5,775	[illegible]	[illegible]
New CTs				
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]

3,000 MW Retirement Scenario				
	CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal				
Gas				
Wind	[illegible]	[illegible]	[illegible]	[illegible]
Solar	[illegible]	36,875	[illegible]	[illegible]
Battery Storage	[illegible]	[illegible]	[illegible]	[illegible]
New CTs	-	-	-	-
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]

Section 4: [illegible] Sensitivity

900 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					7,082	3,082	3,082	7,082
New CTs	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

3,000 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	-	-	-	-		-	-	-
Gas								
Wind								
Solar	-	-	-	-	782	782	782	782
Battery Storage	-	-	-	-	7,082	3,082	3,082	7,082
New CTs	[illegible]	7,120	11,872	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Section 5: [illegible] Sensitivity

900 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					7,082	3,082	3,082	7,082
New CTs	1,113	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

3,000 MW Retirement Scenario								
	BWS/CT Scenario				CDE Mix			
Resource Type	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	-	-	-	-		-	-	-
Gas								
Wind								
Solar	-	-	-	-	782	782	782	782
Battery Storage	-	-	-	-	7,082	3,082	3,082	7,082
New CTs	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8,904
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Section 6: [illegible] Scenario

900 MW Retirement Scenario																										
	Initial Portfolio		BWS/CT Scenario																							
Resource Type	Dec 2022 CDM	Portfolio after Retiring 900 MW of Gas Capacity	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in [illegible] Frequency	Capacity Changes to Achieve 1 in Infinity Frequency	Capacity Changes to Achieve 1 in Infinity Frequency
Coal	13,650	13,650																								
Gas	[illegible]	[illegible]																								
Wind	21,977	21,977																								
Solar	[illegible]	[illegible]																								
Battery Storage	[illegible]	[illegible]																								
New CTs			-	[illegible]	[illegible]	[illegible]	1,957	[illegible]	2,220	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7,120	[illegible]	[illegible]	[illegible]	[illegible]	12,840	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

FREQUENCY

DURATION

MAGNITUDE

[illegible]

No.	FREQUENCY	[illegible]	DURATION	MAGNITUDE	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

No.	FREQUENCY	[illegible]	DURATION	MAGNITUDE	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

No.	FREQUENCY	[illegible]	DURATION	MAGNITUDE	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

No.	FREQUENCY	[illegible]	DURATION	MAGNITUDE	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

No.	FREQUENCY	[illegible]	DURATION	MAGNITUDE	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Attachment D

ERCOT CONE Study

REFERENCE AND ALTERNATIVE TECHNOLOGY SELECTION

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Agenda

Selection of the Reference Technology

Selection of the Alternative Reference Technology

Project Timeline and Next Steps

Reference Technology

Purpose of Reference Technology Selection

Objective: describe a thermal dispatchable plant that is most likely to be developed in ERCOT in the next few years, as a basis for calculating a Cost of New Entry (CONE) metric useful for resource adequacy planning and market parameters

Approach: determine "revealed preference" by reviewing plants recently built and under development

Characteristics included

- Technology type, turbine model, plant size and configuration
- Typical practices for direct electrical interconnection, fuel infrastructure and supply (e.g., dual fuel or firm gas), power augmentation (e.g. turbine inlet air cooling technology), emissions controls, and weatherization

Proposed Specifications for Reference Technology

Technology and Size		
Generation Technology	Aeroderivative Combustion Turbine	Determined from most capacity in recently built or planned dispatchable plants in ERCOT for CODs between 2021-2026
Turbine Model	PROENERGY GE LM6000PC	
Configuration	8 x 0	Based on planned natural gas-fired plants by WattBridge (developer of most gas-fired plant capacity with a COD between 2021-2026)
Nameplate Capacity (MW)	484	
Detailed Design		
Fuel Type	Natural gas, *no* secondary fuel	Based on standard plant design for WattBridge natural gas-fired plants
Combustion Controls	Selective Catalytic Reduction (SCR)	
Power Augmentation	Spray Intercooling (SPRINT)	
Water Supply	Well	
Winterization	Additional cold weather critical components	
Other Project Details		
Location	Harris County	Determined by county with most capacity
Lifetime (Years)	20	Based on standard plant design for WattBridge natural gas-fired plants
Firm Gas Contract	Yes	

Technology Type and Turbine Model

Constructed our "Primary Thermal Dataset" of recently built and planned thermal dispatchable generation with actual or planned COD between 2021 to 2026:

- Data provided by WattBridge
- Cross-referenced against data from Hitachi ABB Velocity Suite, ERCOT CDR report, Texas Commission on Environmental Quality
- Excluded small cogeneration or internal combustion generation plants

This resulted in 14 generators which were all natural gas-fired plants with a total nameplate capacity of 5.1 GW, **98% of capacity is from GE LM6000 aeroderivative combustion turbines**

Thermal Dispatchable Generation in ERCOT (COD 2021 – 2026)

Plant Name	Notes	Technology	Turbine Type	County	Online Date	Number of	Nameplate Capacity
Existing							
Topaz	[1]	Combustion Turbine	GE LM6000	Galveston	10/31/21	10	605
HO Clarke Generating	[2]	Combustion Turbine	GE LM6000	Harris	11/11/21	8	484
Victoria Port Power II	[3]	Combustion Turbine	GE LM6000	Victoria	01/12/22	2	100
Rabbs (Braes Bayou)	[4]	Combustion Turbine	GE LM6000	Fort Bend	05/02/22	8	484
Chamon Power	[5]	Combustion Turbine	GE LM6000	Harris	06/20/22	2	100
Beachwood (Mark One	[6]	Combustion Turbine	GE LM6000	Brazoria	11/30/22	6	363
Colorado Bend	[7]	Combustion Turbine	GE Frame 6B	Wharton	05/31/23	2	78
Brotman	[8]	Combustion Turbine	GE LM6000	Brazoria	10/23/23	8	484
Planned							
Remy Jade	[9]	Combustion Turbine	GE LM6000	Harris	04/01/24	6	363
Beachwood II (Mark On	[10]	Combustion Turbine	GE LM6000	Brazoria	06/01/24	2	121
Remy Jade II	[11]	Combustion Turbine	GE LM6000	Harris	11/30/24	4	242
Sibyl	[12]	Combustion Turbine	GE LM6000	Fort Bend	07/01/25	6	300
Elmax	[13]	Combustion Turbine	GE LM6000	Harris	06/01/26	10	605
LongLeaf	[14]	Combustion Turbine	GE LM6000	Angelina	2026	12	726
	[15] = SUM ([1] to [14]) if LM6000			**Total LM6000 Nameplate Capacity (MW)**			**4,977**
	[16] = SUM ([1] to [14])			**Total Dispatchable Generation Capacity (MW)**			**5,055**
	[17] = [15] / [16]			**LM6000 Share of Total Nameplate Capacity (%)**			**98%**

Notes and Sources: [1] to [14]:
Confidential data provided by ERCOT staff.
Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024.
ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033), December 8, 2023.
Texas Commission on Environmental Quality, Issued Air Permits for Gas Turbines 20 MW or Greater, July 1, 2023.

Configuration and Nameplate Capacity

WattBridge is the developer with most of the recently built and planned thermal dispatchable capacity, which all use the same turnkey natural gas-fired plant design (PROENERGY LM6000PC with SPRINT)

Filtered Primary Thermal Dataset for planned plants by WattBridge to determine most representative configuration and plant capacity resulting in 5 plants (2.1 GW capacity)

Gas-fired plants tend to be built with even-number units, so we selected a **8 x 0 configuration resulting in nameplate capacity of 484 MW** based on the average number of units of planned WattBridge plants and Sargent & Lundy experience

Planned Thermal Dispatchable Generation in ERCOT by WattBridge (COD 2023 – 2026)

Plant Name	Notes	Technology	Turbine Type	County	Online Date	Number of	Nameplate Capacity
Planned							
Remy Jade	[1]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	04/01/24	6	363
Beachwood II (Mark One	[2]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Brazoria	06/01/24	2	121
Remy Jade II	[3]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	11/30/24	4	242
Elmax	[4]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Harris	06/01/26	10	605
LongLeaf	[5]	Combustion Turbine	PROENERGY GE LM6000PC with SPRINT	Angelina	2026	12	726
	[6] = Average([1] to [5])				**Average**	**7**	**411**

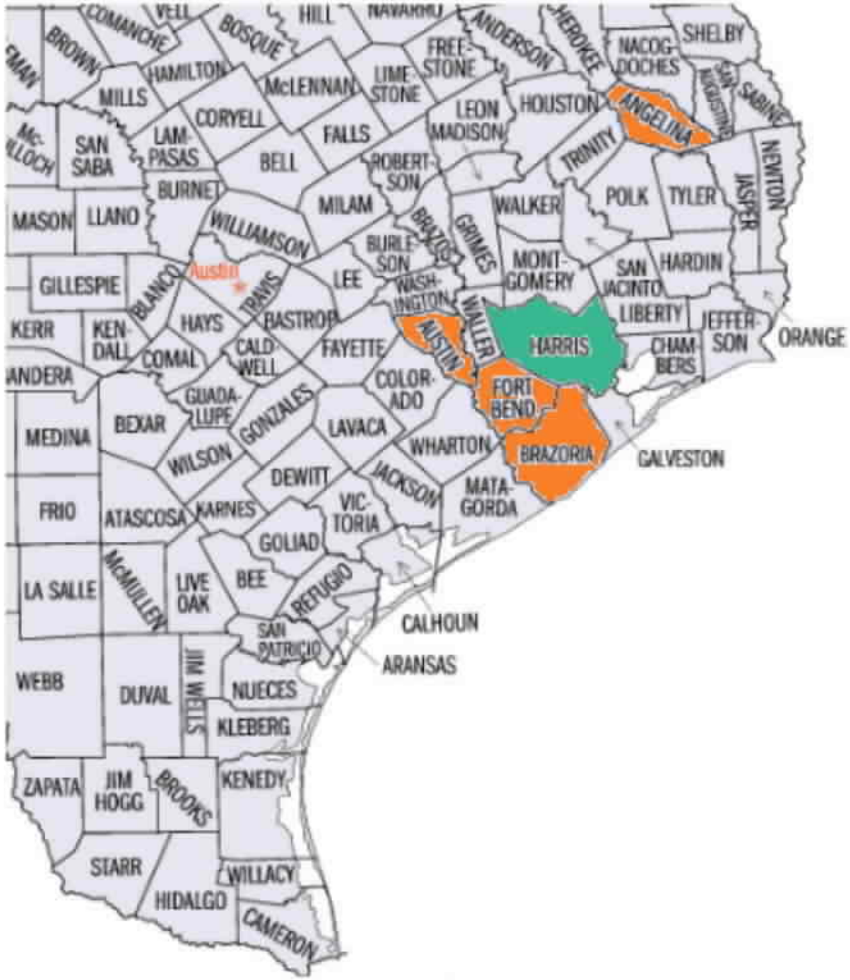
Notes and Sources: [1] to [5]:
Confidential data provided by ERCOT staff.
Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024.
ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033), December 8, 2023.
Texas Commission on Environmental Quality, Issued Air Permits for Gas Turbines with Electric Output 20 MW or Greater, July 1, 2023.

Location

All of the planned gas-fired plants are located in 5 counties in Southeast Texas

51% of planned natural gas generation capacity is in Harris County (highlighted in green), so Harris county was selected as the location

Locations of Planned Thermal Dispatchable Gas Capacity in ERCOT (COD 2023-2026)



Sources: Confidential data provided by ERCOT staff; Hitachi ABB Velocity Suite, Generating Unit Capacity Dataset, January 22, 2024; ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT region (2024-2033), December 8, 2023; Texas Commission on Environmental Quality, Issued Air Permits for Gas Turbines with Electric Output 20 MW or Greater, July 2, 2023.

Alternative Reference Technology

Purpose of Alternative Technology Selection

Objective: describe a dispatchable renewable plant that is most likely to developed in ERCOT in the next few years as a basis for sensitivity analysis of the Cost of New Entry (CONE) reliability metric

Approach: again use "revealed preference" based on developers' actual plants/plans

Characteristics to include:

- Generator technology type and size
- Storage technology type, size, and duration
- Location of a representative plant
- Typical engineering design for power coupling, DC / AC ratio, battery chemistry and battery augmentation schedule

Proposed Specifications for Alternative Reference Technology

Technology and Size		
Generation Technology	PV + BESS Hybrid ("Solar Hybrid")	Determined by alternative technology type with most capacity in recently built or planned plants in ERCOT for CODs 2021-2026
PV Capacity (MW)	200	Determined by assessing median plant size, median solar-to-storage ratio, and median duration
Storage Capacity (MW)	100	
Storage Duration (Hours)	2	
Detailed Design		
PV Module Technology	Monocrystalline Bifacial Panels	Determined by most prevalent characteristics in recently built or planned solar hybrid plants in ERCOT with CODs 2021 - 2026
PV Tracking System	Single-axis tracker	
PV DC / AC Ratio	1.3	Determined by median PV DC / AC ratio
Storage Technology	Lithium-ion	Determined by most prevelent storage technology
PV-BESS Coupling	AC Coupled (separate inverters)	Determined by most prevalent coupling design
Other Project Details		
Location	Brazoria County	Determined by county with most capacity
Lifetime (Years)	20	Lifetime chosen from typical design for plant type based on Sargent & Lundy expertise
Storage Augmentation	Every 5 years	Median augmentation frequency based on Sargent & Lundy expertise and review of similar sized solar hybrid plants

Alternative Reference Technology and Lifetime

Created "Primary Solar Hybrid Dataset" by filtering ERCOT January 2024 GIS Report and confidential duration data provided by ERCOT staff (70 plants and 20 GW of capacity), considering plants:

- with a COD between 2021-2026
- excluded those without storage
- separated those with and without a signed Interconnection Agreement

Solar hybrid and standalone storage are both prevalent

Solar hybrid was selected because it is dispatchable and produces primary energy

Comparison of Existing or Planned Storage and Generator Capacities for Hybrid and Standalone Storage Plants in ERCOT (COD 2021 – 2026)

Technology	Notes	Existing		Planned with IA		Planned without IA	
		Storage Capacity (MW)	Generator Capacity (MW)	Storage Capacity (MW)	Generator Capacity (MW)	Storage Capacity (MW)	Generator Capacity (MW)
Solar Hybrid	[1]	1,264	4,214	8,881	15,928	16,736	25,332
Wind Hybrid	[2]	224	698	195	582	100	435
Thermal Hybrid	[3]	263	358	0	0	0	0
Standalone Storage	[4]	2,468	0	13,495	0	64,422	0

Notes and Sources: IA = Interconnection Agreement.
[1] to [4]:
Confidential data provided by ERCOT staff;
ERCOT, January 2024 Generator Interconnection Status (GIS) Report, February 12, 2024.

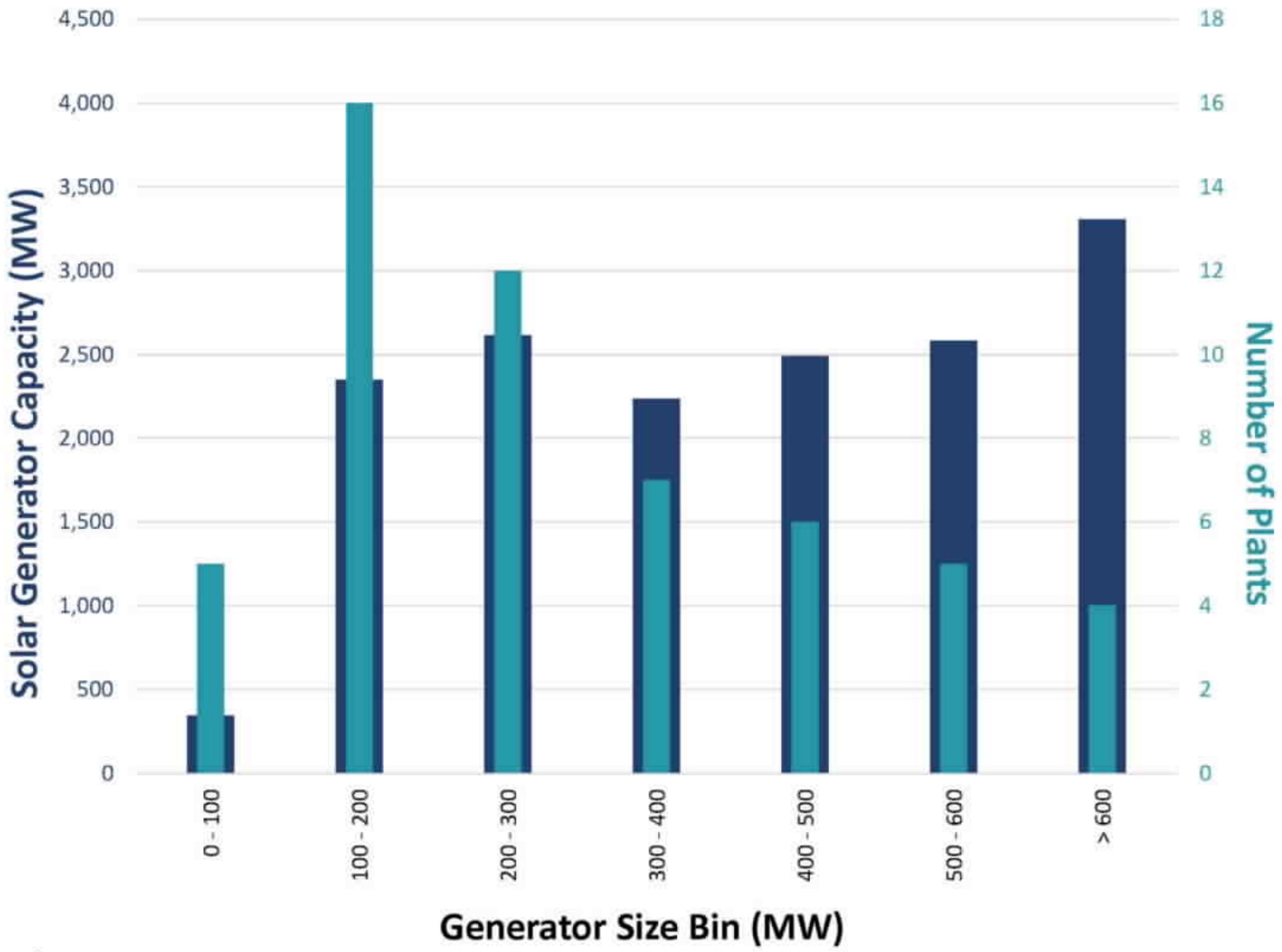
PV Capacity

Filtered the Primary Solar Hybrid Dataset for only planned plants with a signed Interconnection Agreement (IA) which resulted in 55 plants total (16 GW)

The histogram on the right displays the number of plants (**teal, right axis**) and solar generation portion of capacity (**blue, left axis**) for the planned solar hybrid plants and shows grouping around 200 MW, the median generator size is 204 MW

Based on the distribution of solar generator sizes, we selected **200 MW** to be the representative solar capacity

Planned ERCOT Solar Generation Capacity and Solar Hybrid Plants Size Distribution (COD 2023-2026)



Sources:
Confidential data provided by ERCOT staff;
ERCOT, January 2024 GIS Report, February 12, 2024.

PV Module Technology and Tracking System

Cross referenced the Primary Solar Hybrid Dataset (70 plants) with confidential solar project data prepared by UL Solutions for ERCOT, which resulted in 29 solar hybrid plants (7.8 GW of capacity) that overlapped between the two datasets

Based on these 29 solar hybrid plants, 58% of solar hybrid capacity has monocrystalline solar panels, 54% has bifacial solar panels, and 74% has a single-axis tracking system

Additionally, Sargent & Lundy reviewed their extensive project database and public sources (Form EIA-860) for ERCOT solar hybrid projects which confirmed our analysis, so we selected a PV system with **monocrystalline and bifacial solar panels with a single-axis tracking system**

PV Technology Characteristics of Existing or Planned Solar Hybrid Plants (COD 2021-2026)

PV Module Technology	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Monocrystalline	[1]	17	4,534	58%
Polycrystalline	[2]	1	601	8%
Thin Film	[3]	3	698	9%
Unknown	[4]	8	1,936	25%
Sum	**[5] = SUM([1]:[4])**	**29**	**7,769**	**100%**

Solar Panel Type	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Bifacial	[1]	14	4,174	54%
Not Bifacial	[2]	7	1,659	21%
Unknown	[3]	8	1,936	25%
Sum	**[4] = SUM([1]:[3])**	**29**	**7,769**	**100%**

Tracking System	Notes	Plants	Total Capacity (MW)	Share of Capacity (%)
Single	[1]	21	5,769	74%
Dual	[2]	1	210	3%
Unknown	[3]	7	1,791	23%
Sum	**[4] = SUM([1]:[3])**	**29**	**7,769**	**100%**

Notes and Sources: Confidential data provided by ERCOT staff; ERCOT, January 2024 GIS Report, February 12, 2024.

Storage Technology, Storage Capacity, and Duration

From our Primary Solar Hybrid Dataset (70 plants total), all storage systems were lithium-ion and the median duration and median storage-to-solar capacity ratio were 2-hours and 50%, therefore we selected **a lithium-ion battery system with a 2-hour duration and 50% storage-to-solar capacity ratio**

Based on the 200 MW PV generator size and the 50% storage-to-solar capacity ratio, we selected a **100 MW storage capacity**

Storage Durations for Existing or Planned Solar Hybrid Plants vs. Standalone Storage in ERCOT (COD 2021 – 2026)

Technology	Existing		Planned with IA	
	Median Storage Duration (Hrs)	Median Storage / Solar Capacity Ratio (%)	Median Storage Duration (Hrs)	Median Storage / Solar Capacity Ratio (%)
Solar Hybrid	1.5	34%	2.0	50%
Standalone Storage	1.0		1.1	

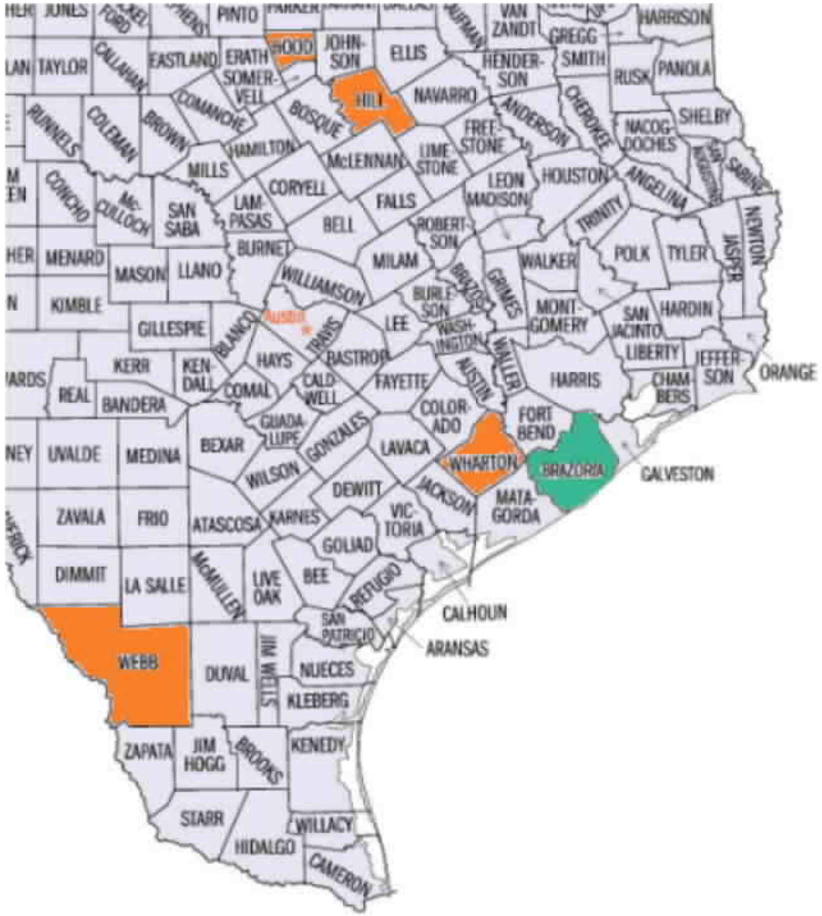
Notes and Sources: IA = Interconnection Agreement.
Confidential data provided by ERCOT staff;
ERCOT, January 2024 GIS Report, February 12, 2024.

Location

Filtered the Primary Solar Hybrid Dataset for only planned plants which resulted in 55 plants total (16 GW)

37% (5.8 GW) of solar generator capacity is in the top 5 counties (see the highlighted counties in the map) and Brazoria County (in green) is the county with the most capacity and contains 12% (1.9 GW) of the total, so we selected **Brazoria County as the reference location**

Locations of Planned Solar Hybrid Plants in ERCOT (COD 2023 – 2026)



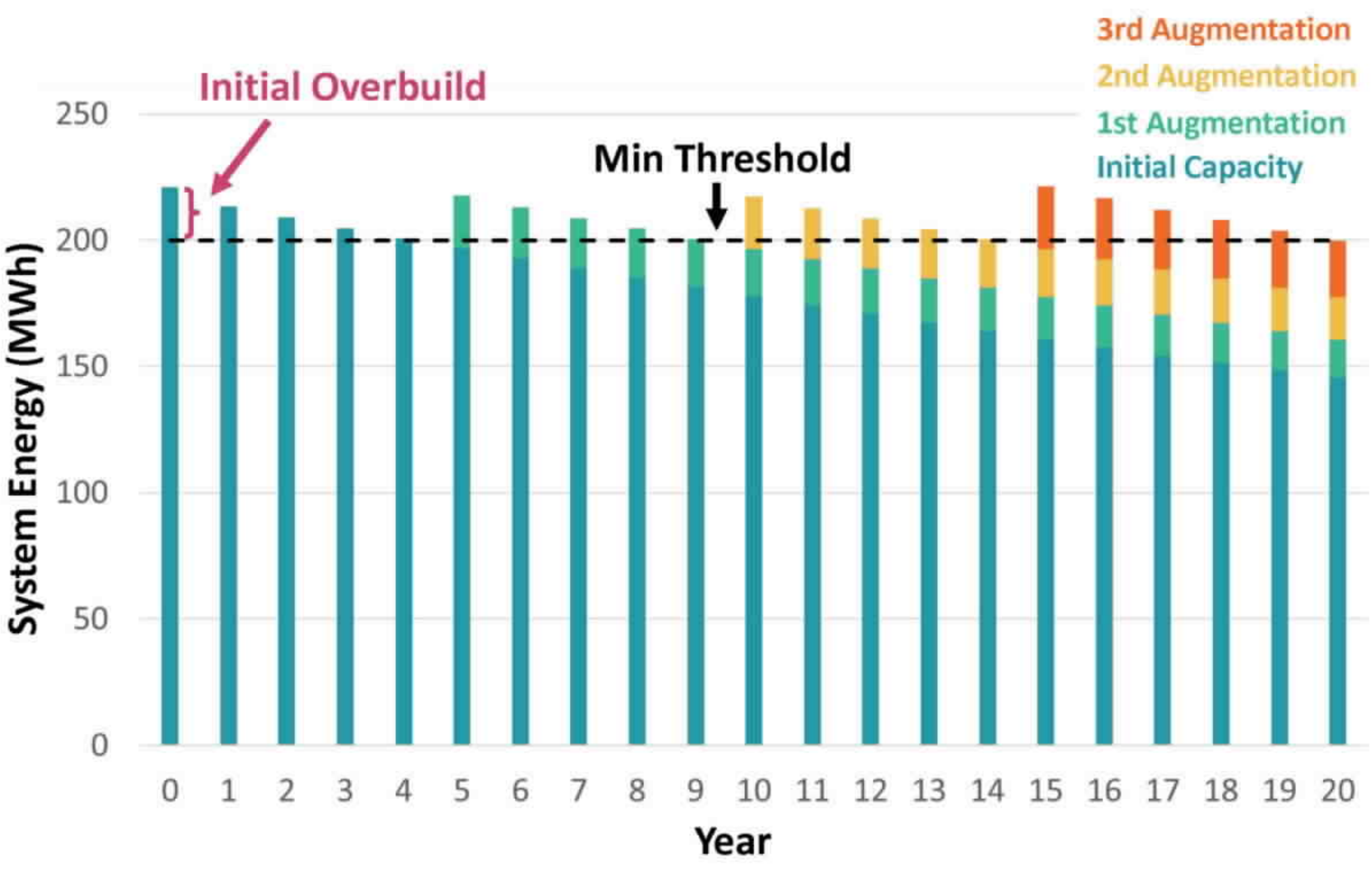
Sources:
Confidential data provided by ERCOT staff;
ERCOT, January 2024 GIS Report, February 12, 2024.

Storage Augmentation (1/2)

Problem of battery degradation: Li-ion battery systems degrade due to time, usage, and environmental factors. This degradation impacts the capacity, duration, and efficiency of the storage system, so to maintain capabilities as sized for the interconnection and hybrid system (as well as contract and warranty terms) mitigation techniques are needed.

Storage augmentation: is a common practice for Li-ion storage systems which entails over-building a fixed percentage of design capacity and over-designing some system components (such as battery module rack space) to later enable battery modules to be added (augmented) during the project lifetime to offset degradation during normal system operations.

Illustrative Example of BESS Overbuild and Augmentation Approach



Storage Augmentation (2/2)

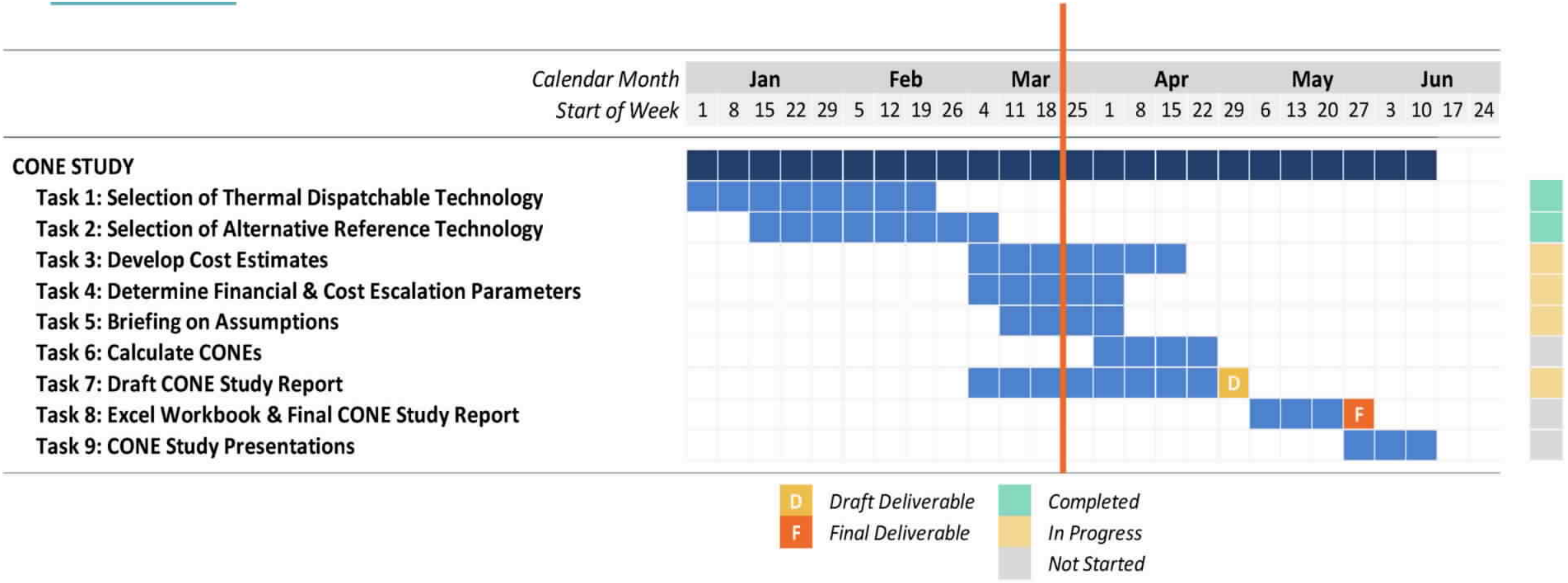
How augmentation frequency is determined: if the project's financial plan includes augmentation, the frequency may depend on several factors including the project use case, battery degradation profile, capacity requirements of project agreements, site space availability constraints, and anticipated costs for batteries at the anticipated dates of augmentation.

How we selected the augmentation approach: the battery cycling and augmentation frequency we selected is based on a review of financial models from several similar PV+BESS installations and the median augmentation period. In ERCOT, solar hybrid plants are intended primarily for energy shifting. Based on our review, for this service we assumed on average one cycle per day for the battery storage component and predict annual degradation based on battery manufacturer warranty curves for the anticipated time and energy throughput. We selected an augmentation frequency of every 5 years with an initial overbuild to ensure the energy capacity exceeds the minimum required system output.

How this is included in CONE calculation: this is included as separate line items to i) fixed O&M cost based on an annualized cost of storage augmentation over the project lifetime and ii) CAPEX based on the additional balance of plant equipment (e.g., reserved rack space and conductors) included in the initial construction to accommodate future augmentation.

Timeline and Next Steps

Project Timeline



Next Steps

Develop Cost Estimates for Reference and Alternative Technologies

Determine Financial and Cost Escalation Parameters