Assessment of Market Reform Options to Enhance Reliability of the ERCOT System

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Energy+Environmental Economics

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Table of Contents

Acronyms

Acronym	Definition
4CP	4 Coincident Peak
AS	Ancillary Services
BRS	Backstop Reliability Service
CDR	Capacity, Demand and Reserves (ERCOT Report)
CONE	Cost of New Entry
CT	Combustion Turbine
DEC	Dispatchable Energy Credit
ECRS	ERCOT Contingency Reserve Service
ERS	Emergency Response Service
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate on Demand
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
E3	Energy and Environmental Economics, Inc.
FFRS	Fast Frequency Response Service
FRM	Forward Reliability Market
IMM	Independent Market Monitor
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LR	Load Resource
LSE	Load Serving Entity
LSERO	Load Serving Entity Reliability Obligation
ORDC	Operating Reserve Demand Curve
PBPC	Power Balance Penalty Curve
PCM	Performance Credit Mechanism
PRD	Price Responsive Demand
PUCT	Public Utility Commission of Texas
PUNS	Private Use Networks
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
RRS	Responsive Reserve Service
SERVM	Strategic Energy & Risk Valuation Model
TDSP	T&D Service Providers

Glossary

- **1-Day-in-10-Years:** Shorthand for a common electricity industry reliability standard that specifies that an electricity system must have sufficient generating resources to serve load all but one day every ten years. This standard is equivalent to 0.1 days per year loss of load expectation.
- **Accreditation:** The process by which a generating unit is assigned a value that quantifies its contribution to system reliability. An accredited generator has *Effective Capacity* (see definition below).
- **Ancillary Services:** The services necessary to support grid stability and security, including real-time operating reserves that maintain reliability despite expected and unexpected fluctuation in system demand and supply.
- **Backstop Resources:** Resources that are held in reserve by ERCOT (i.e., not active participants in the electricity market) and are utilized to maintain reliability if needed due to insufficient other resources.
- **Bilateral Procurement:** Procurement executed through individual contracts between a generator and an LSE.
- **Capacity Factor:** The ratio of the electrical energy produced by a generating unit for the period considered relative to the electrical energy that could have been produced at continuous full power operation during the same period.
- **Centralized Procurement:** Procurement executed through a centralized auction for all supply and demand in the market.
- **Cost of New Entry (CONE):** The levelized all-in cost of a new resource, including capital expenditures, financing costs, and fixed operations and maintenance. This total cost is often normalized by generator capacity (kW) and then amortized over the life (years) of the resource into a final metric of "dollars per kilowatt per year" ($/kW-yr). In this study, CONE is used primarily in reference to the marginal capacity resource (calculated through modeling to be a natural gas combustion turbine).
- **Cost of Retention:** The levelized go-forward costs of an existing resource. In this study, the value refers to the levelized go-forward cost of the reference marginal retention resource (coal).
- **Demand Response:** Reductions in electricity consumption by consumers in response to economic signals, with the goal of reducing usage during high reliability risk hours.
- **Dispatchable Energy Credit (DEC):** A credit that is generated when energy or ancillary services are produced/provided from an eligible dispatchable resource. In this study, an eligible dispatchable resource must be able to start in 5 minutes or less, have less than a 9,000 Btu/kWh heat rate, and be able to dispatch continuously for 48 hours or more.
- **Equivalent Forced Outage Rate on Demand (EFORd):** Measure of the probability that a generating unit will be forced offline (not be available due to forced outages or forced derating) when there is demand on the unit to generate; This is an input in reliability modeling and an important determinant of a resource's Effective Capacity.

- **Effective Capacity:** A measure of a generating unit's expected availability during hours of highest reliability risk (typically aligned with hours of peak net load); this metric can be reported in MW or %, where the % value is calculated by dividing Effective Capacity MW by Maximum Capacity MW. Because no resource is perfect (i.e., available at its Maximum Capacity in all hours), all resources have an Effective Capacity of less than 100%.
- **Effective Load Carrying Capability (ELCC):** A specific methodological approach to calculating a resource's Effective Capacity. The ELCC of a specific resource is calculated as the quantity of perfect capacity (MW) required to yield the same level of system reliability as the specific resource. For example, if an electricity system with 50 MW of a perfect resource yields the same level of reliability as an electricity system with 100 MW of battery storage, then the ELCC of battery storage is 50%.
- **Expected Unserved Energy (EUE):** A reliability metric that provides the total quantity of energy per year (MWh/year) that the system is expected to not be able to serve due to insufficient resources.
- **Ex-ante:** Calculated in advance of actual system conditions based on a forecast.
- **Ex-post**: Calculated after actual system conditions based on actual data.
- **Forced Outage:** The shutdown condition of a generating unit when it is unavailable to produce electricity / offline due to an unexpected breakdown.
- **Forward Market:** A market where a product is transacted in advance and actual creation/delivery.
- **Generation Stack:** A ranking of generating resources from lowest dispatch cost to highest dispatch cost to determine the order in which resources will dispatch to minimize total system costs. This is equivalent to the short-run energy supply curve.
- **Independent Market Monitor (IMM):** An organization or individual retained by an ISO to evaluate the performance of the markets and identify conduct by market participants or the ISO that may compromise the efficiency or distort the outcomes of the markets.
- **Independent System Operator (ISO):** an organization that coordinates, controls, and monitors the electric grid in a specific geographical, sometimes multi-state region; Texas' ISO is ERCOT.
- **Load:** The amount of electricity that is being consumed in a given electrical system.
- **Load-Ratio Share:** The share of total system load that a specific LSE is responsible to serve, for a specific point in time.
- **Load Serving Entity (LSE):** An entity that procures electricity from the ERCOT market and supplies electricity to individual customers.
- **Loss of Load:** An event when the available electricity generation capacity (electricity supply) is lower than and therefore cannot meet the system load (electricity demand), requiring the system operator to interrupt electric service to a subset of customers.
- **Loss of Load Expectation (LOLE):** This metric provides the total number of days per year (days/year) that the system is expected to have loss of load of any size or duration. This metric measures the number of days that have any quantity of loss of load. For example, a day with 1 hour or a day with 23 hours of lost load would both count as "one day" toward this metric.

- **Loss of Load Hours (LOLH):** This metric provides the total number of hours per year (hours/year) that the system is expected to have loss of load.
- **Loss of Load Probability (LOLP):** This probability that the system is expected to have loss of load during a specified time period.
- **Margins:** The net revenues received by a generating unit, which are calculated as total revenues minus total variable costs. Margins contribute toward fixed cost recovery, including capital expenditures and fixed operations and maintenance costs.
- **Market Power:** The ability of a market participant to influence the price of a product by manipulating either the supply or demand of the product to increase economic profit.
- **Missing Money:** The additional money that a generator needs beyond what it earns in the energy and ancillary services market to recover its upfront capital expenditures and fixed operations and maintenance costs.
- **Operating Expenses (Opex):** The ongoing (not fixed) cost of operating a generating unit. These include costs such as fuel and variable operations and maintenance expenses.
- **Operating Reserve Demand Curve (ORDC):** An administratively-determined function used to increase the real-time price of energy and ancillary services in the ERCOT market based on the quantity of available real-time operating reserves.
- **Peak Load (equivalently, Peak *Gross* Load):** The maximum total electricity demand in a system in a specified time period (usually a year).
- **Peak Net Load:** The maximum total electricity demand in a system during a specified time period (usually a year), net of wind, solar, and storage generation.
- **Planned Outage:** The shutdown condition of a generating unit when it is unavailable to produce electricity / offline due to a deliberate decision, such as planned maintenance.
- **Price Cap:** A form of economic regulation that establishes an upper limit on the prices that an entity can offer to sell a specific product.
- **Reliability Resource:** A resource that provides value to a system by contributing to system reliability requirements.
- **Renewable Energy Credit (REC):** A credit that is generated when energy is produced from a renewable resource, including but not limited to wind and solar.
- **Renewable Portfolio Standard (RPS):** A regulation that sets a requirement on the annual amount of energy production from renewable resources, including but not limited to wind and solar.
- **Settlement Process:** An exchange of a product/service where the seller transfers the product/service and the buyer transfers the payment.
- **Technology-Neutral:** A characteristic of a market design that values all generating units based solely on their capabilities, regardless of the underlying technology of each generating unit.

1 Executive Summary

This report provides an independent assessment of potential long-term market design reform options to promote the supply of dispatchable generation and focus on reliability as outlined in Phase II of the "Blueprint" published by the Public Utility Commission of Texas (PUCT) in December 2021.[1] Under the direction of the PUCT and its Staff, the consulting team of Energy and Environmental Economics (E3) and Astrapé Consulting ("the Consulting Team") developed and analyzed six specific market design options, listed in Table 1 below, and compared the impacts of each against a status quo Energy-Only market design.

Table 1. Overview of Market Designs Analyzed

Market Design	Description
Energy-Only (Status Quo)	• Preserves existing energy-only and ancillary service market design as is (no explicit reliability standard) • Incorporates the implementation of the Blueprint's Phase I enhancements
Load Serving Entity Reliability Obligation: LSERO	• Establishes a reliability standard and identifies the corresponding quantity of reliability credits – assigned to resources using marginal ELCC – that are needed to meet that standard • Requires each LSE to procure reliability credits from generators bilaterally to meet its share of the total system requirement based on forecasted pro-rata consumption during hours of highest reliability risk
Forward Reliability Market: FRM	• Establishes a reliability standard and identifies the corresponding quantity of reliability credits – assigned to resources using marginal ELCC – that are needed to meet that standard • Creates a mandatory, centrally-cleared forward market for reliability credits administered by ERCOT that clears based on a sloped demand curve, with cost allocation to LSE based on pro-rata consumption during hours of highest reliability risk
Performance Credits Mechanism: PCM	• Establishes a reliability standard and a corresponding quantity of performance credits (PCs) that must be produced during hours of highest reliability risk to meet this standard • Establishes a retrospective settlement process through which PCs are awarded to resources based on availability during hours of highest risk and purchased by LSEs according to their load-ratio share during those same periods at a price determined by an administrative demand curve • Allows generators and LSEs to trade PCs in a voluntary forward market; participation in the forward market is required for generators to qualify for the retrospective settlement process
Backstop Reliability Service: BRS	• Authorizes ERCOT to procure backstop resources sufficient to maintain a reliability standard based on a forward-looking assessment • Backstop resources are deployed last in the bid stack to avoid impact on day-ahead and real-time energy & ancillary service prices to help avoid emergency conditions in system reliability • Allocates cost of backstop procurement to LSEs based on pro-rata consumption during hours of highest reliability risk
Dispatchable Energy Credits: DEC	• Requires each LSE to procure dispatchable energy credits (DECs) from eligible resources at a quantity equal to 2% of its annual energy (MWh) load • DECs can be generated by resources with a 5-min startup time, below 9,000 Btu/kWh heat rate, and 48-hour duration that clear in energy & ancillary service markets between 6-10 pm in any day
Dispatchable Energy Credits + Backstop Reliability Service: DEC/BRS Hybrid	• This design merges the DEC and BRS design

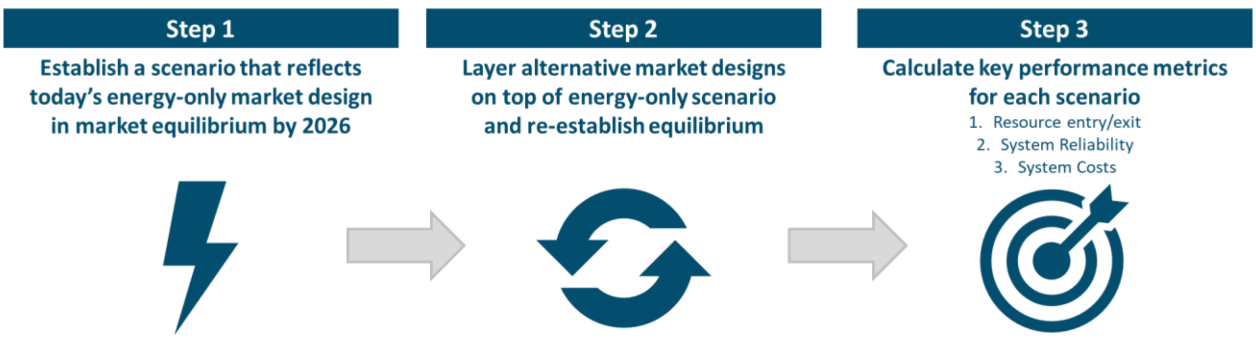
[1] https://interchange.puc.texas.gov/Documents/52373_336_1180125.PDF.

1.1 Methods and Assumptions

The various market design reforms evaluated in this study will introduce new requirements, market products, and settlement processes to ERCOT's energy-only market. By altering the revenue streams available to generators, each design will impact the choices made by power producers to invest in new resources and maintain and operate existing ones, resulting in changes to the composition of resources on the grid, the corresponding level of reliability provided to ERCOT consumers, and the costs for which they are responsible.

To quantify these impacts, this study analyzes each design under a condition of "market equilibrium," meaning that the mix of generation resources on the system are adjusted to account for the expected market response to the economic signals introduced by each design. This assumes that market participants respond to the specific incentives introduced by each market design by investing in new generation or retiring existing generation to maximize profits. This assumption of market efficiency ensures that all market designs are evaluated on a consistent basis. Figure 1 provides a graphical overview of the study approach.

Figure 1. Overview of Study Approach



E3 subcontracted with Astrapé Consulting to use the **Strategic Energy & Risk Valuation Model (SERVM)** to simulate the outcomes of the ERCOT energy and ancillary services markets for each design. This model has been used extensively by ERCOT in prior reserve margin studies. This study used a proprietary version of the model that Astrapé has developed for ERCOT to perform the *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*[2]. Several key updates were made to accommodate current and future states; most significantly, changes to natural gas prices, expected loads, and expected resource entry/exit for 2026.

All market designs (Energy-Only and market design reform proposals) are analyzed inclusive of Phase I reliability reforms that were approved by the PUCT in December 2021. These reliability reforms include: modifications to the operating reserve demand curve (ORDC), creation of a firm fuel product, accelerated implementation of the new ERCOT Contingency Reserve Service (ECRS) ancillary service product, implementation of reforms to the Emergency Response Service (ERS), and implementation of a new Fast

[2] https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf.

Frequency Response Service (FFRS). Thus, this study measures the impact of additional market design reforms *relative to* the Phase I reforms.

The analysis in this study focuses on the snapshot year of 2026, a near-term year that was intentionally selected by the Consulting Team as 1) near-term enough that there is relative certainty about expected loads and resources but 2) long-term enough that any potential market design reform could be implemented.

Regarding expected 2026 load, the Consulting Team assumed a total annual load of 470 TWh, based on ERCOT's 2022 Long-Term Hourly Energy Forecast Study.[3] This total electricity consumption represents a 20% growth from ERCOT's actual load in 2021 (393 TWh).[4]

The resource portfolios for each market design, summarized in Table 2, include three categories of resources:

1. **2022 existing resources:** all existing resources based on the 2022 Seasonal Assessment of Resource Adequacy (SARA) report are included in each portfolio.
2. **CDR additions and retirements:** based on direction provided by PUCT, all portfolios include planned resource additions and retirements between 2022-'26 from ERCOT's May 2022 Capacity, Demand and Reserves (CDR) report.[5] The CDR report shows significant quantities of renewables and energy storage added to the system over this period.
3. **Equilibrium adjustments (design-specific):** Equilibrium is achieved by adjusting the quantity of coal and natural gas resources under each design such that the net margins earned by the marginal capacity resource across all potential market products (energy, ancillary services, or other new market products if applicable) are equal to its cost of new entry (CONE).[6] This study finds that the marginal capacity resource is a natural gas combustion turbine (CT), meaning this is the most economic source of incremental capacity.[7] ***These equilibrium adjustments are an output from, rather than an input to, the analysis, and the quantity of adjustments varies by design.***

[3] https://www.ercot.com/files/docs/2022/02/10/2022_LTLF_Hourly.xlsx.

[4] Based on ERCOT's historical data, https://www.ercot.com/gridinfo/load/load_hist.

[5] Report: https://www.ercot.com/files/docs/2022/05/16/CapacityDemandandReservesReport_May2022.pdf; Backup data: https://www.ercot.com/files/docs/2022/05/16/CapacityDemandandReservesReport_May2022.xlsx.

[6] This approach of adjusting CT capacity yields a partial equilibrium with respect to generation capacity and reliability outcomes. A true equilibrium would adjust the quantity of each resource based on its net profits; however, achieving a true equilibrium would require a substantial amount of additional modeling effort and was beyond the scope of this study.

[7] The Consulting Team also analyzed a sensitivity to evaluate an alternative equilibrium perspective based on a generating unit's "low cost of retention" (net margins required to keep the unit online and operating) instead of a "cost of new entry" (net margins required to build a new unit).

Table 2. Resources Included in Study Under Base Case Assumptions (MW)

Resource Type	Total Installed Summer Capacity, 2022	Net CDR Additions & Retirements, 2022-2026	Equilibrium Adjustments	Total Installed Summer Capacity, 2026
Nuclear	4,973	–	–	**4,973**
Coal	13,568	–	*Adjustments vary by market design*	***Totals vary by market design***
Natural Gas	48,479	+375		
Hydro [1]	372	–	–	**372**
Biomass	163	–	–	**163**
Wind	35,210	+5,394	–	**40,605**
Solar	11,992	+27,335	–	**39,347**
Battery Storage	2,014	+5,397	–	**7,411**
Other [2]	12,134	–	–	**12,134**

Notes:

1. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
2. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

Each market design reform option is evaluated quantitatively and qualitatively.[8] Quantitative results include:

1. Resource entry/exit (MW)
2. Reliability
    a. Loss of load expectation (LOLE)
    b. Loss of load hours (LOLH)
    c. Expected unserved energy (EUE)
3. System costs ($ per year)

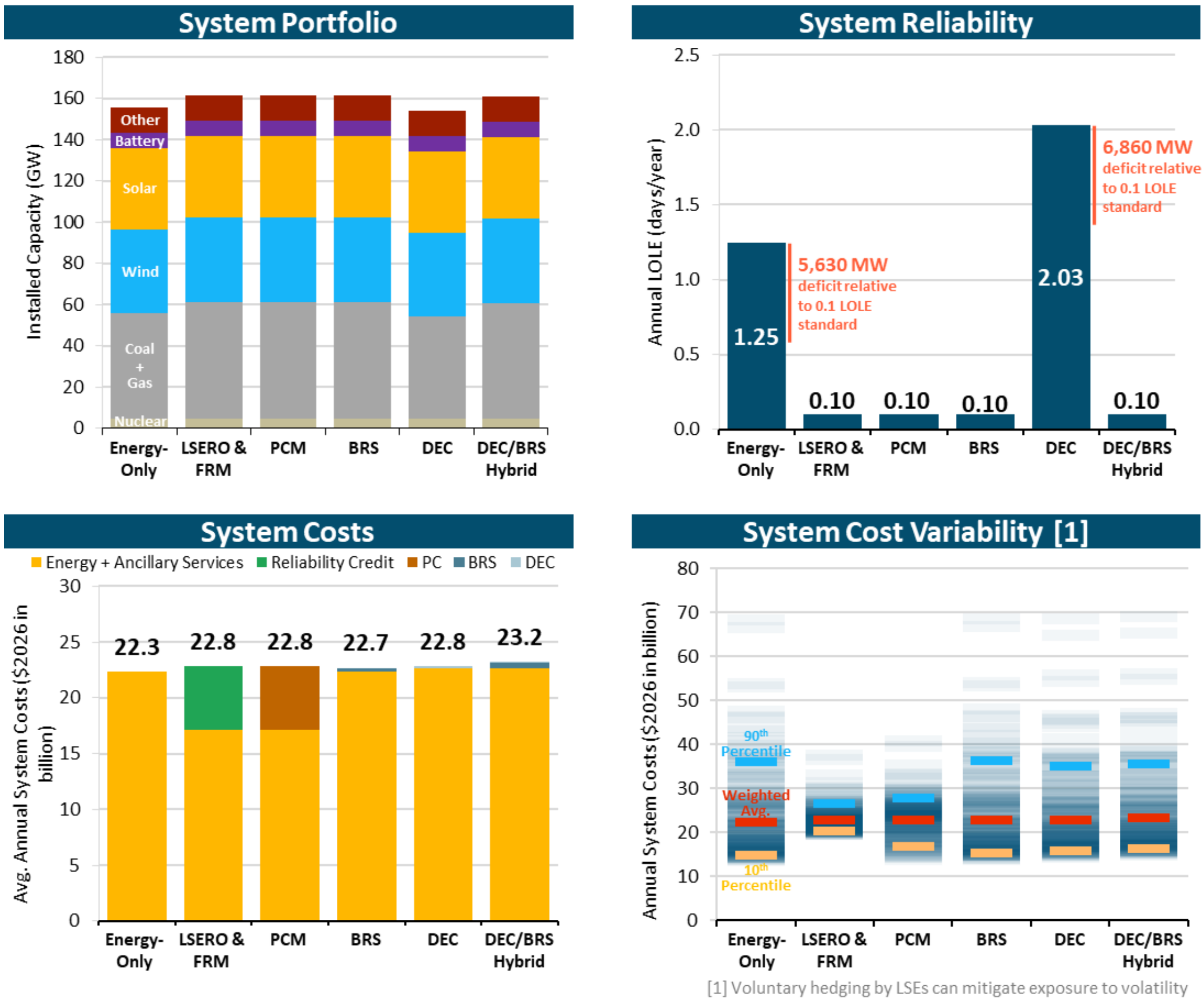
In addition to the quantitative metrics listed above, E3 evaluated each market design along a number of qualitative metrics: market power risk, market competition and efficiency, implementation timeline, administrative complexity, real-time performance incentives and penalties, ability to address extreme weather events, cost and revenue stability, load migration, demand response, and prior precedent. E3 used a simple "stoplight" scoring process where red indicates concern, green indicates no concern, and yellow is neutral. The qualitative categories considered are based on stakeholder and PUCT comments and represent E3's independent view.

[8] The LSERO and FRM are assumed to perform identically in the quantitative analysis, since the theory and economic signals are the same. The difference between the proposals is that the FRM has a mandatory forward auction whereas the LSERO relies on a bilateral market. Both markets would achieve the same equilibrium in an efficient market; the key analytical distinctions between the two are therefore qualitative and related to which design is more likely to approach market efficiency in practice.

1.2 Analytical Results

A summary of key system portfolio changes, reliability, and costs under Base Case assumptions is provided in Figure 2 below.

Figure 2. Summary of Quantitative Results for Base Case



+ Under equilibrium conditions, the 2026 Energy-Only design results in a portfolio with a loss of load expectation of 1.25 days per year, far above the common industry standard of 0.1 days per year. Due to the significant level of renewable and storage additions assumed in the Base Case, the Energy-Only design results in the exit of 11,260 MW of coal and natural gas generating capacity. This design has a projected 2026 total system customer costs of $22.3 billion per year.
+ The LSERO, FRM, and PCM designs result in an incremental 5,630 MW of natural gas capacity relative to the Energy-Only portfolio. This improves loss of load expectation to 0.1 days per year at an incremental cost of $460 million per year.
+ The BRS design results in an incremental 5,630 MW of natural gas capacity relative to the Energy-Only portfolio. These BRS resources are held in reserve by ERCOT at an incremental cost of $360 million per year, resulting in an improvement of loss of load expectation to 0.1 days per year.

- The DEC market design results in a reduction of aggregate natural gas generation since new DEC-eligible resources leads to the exit of non-DEC-eligible natural gas generation. This increases loss of load expectation to 2.03 days per year. The increase in scarcity pricing and cost of the DEC product increase costs by $490 million per year.
- A market design combining the DEC and BRS designs achieves a loss of load expectation of 0.1 days per year at an incremental cost of $920 million per year.
- LSERO and FRM market designs decrease annual variability of natural gas CT margins to within the range of $83/kW-yr (10th percentile) to $124/kW-yr (90th percentile), a significantly narrower band than the Energy-Only design, which yields CT margins generally within the range of $0/kW-yr to $260/kW-yr.

A more detailed breakdown of system costs by component is provided Table 3 below.

Table 3. System Costs by Category for Base Case

	Base Case Costs ($B/yr)					
	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Energy & Ancillary Services	$22.33	$17.12	$17.12	$22.33	$22.67	$22.67
Reliability Credits	–	$5.67	–	–	–	–
Performance Credits	–	–	$5.67	–	–	–
Backstop Service	–	–	–	$0.36	–	$0.43
Dispatchable Energy Credits	–	–	–	–	$0.15	$0.15
Total System Cost	**$22.33**	**$22.79**	**$22.79**	**$22.69**	**$22.82**	**$23.25**
Incremental Reform Cost	–	**+$0.46**	**+$0.46**	**+$0.36**	**+$0.49**	**+$0.92**

1.3 Sensitivity Analysis

In addition to evaluating each market design under the assumptions described above, the Consulting Team also analyzes each market design under “High Renewable”, “High Gas Price”, and “Low Cost of Retention Equilibrium” sensitivity scenarios to understand how robust the performance of each market design is to future key uncertainties.

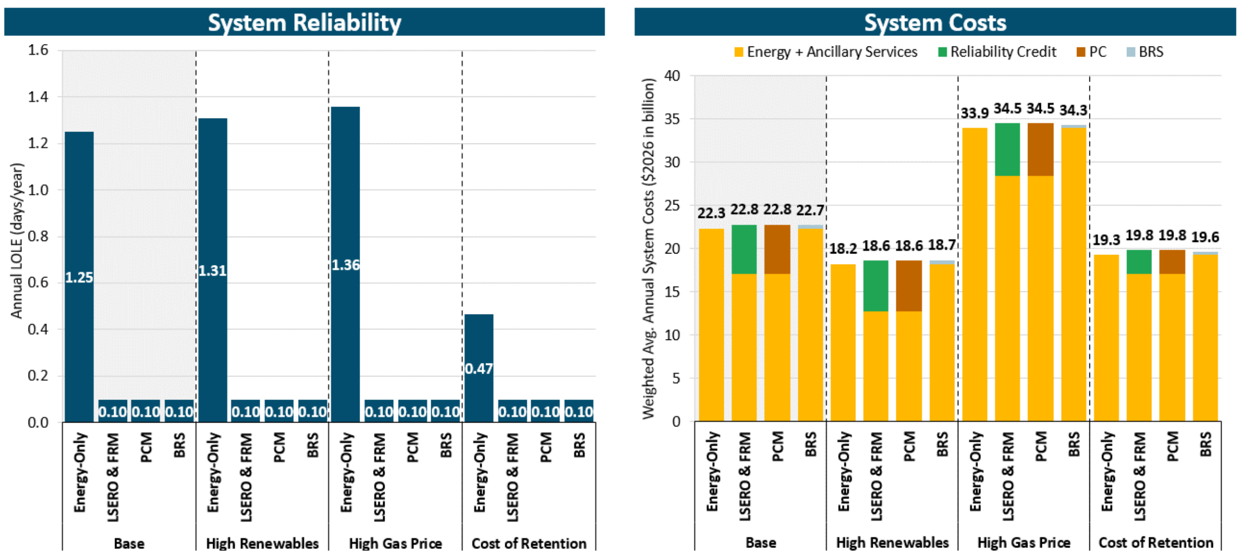
A summary of key reliability and costs results under key sensitivity tests are provided in Figure 3 below.

- The “High Renewable” sensitivity increases total renewable, storage, and demand response capacity in the system. This sensitivity yields a similar reliability to the Base Case in the Energy-Only scenario (1.31 days per year loss of load expectation), and the same target reliability (0.1 days per year loss of load expectation) for the LSERO, FRM, PCM, and BRS by design. System costs decrease across all design options because of reduced energy cost of renewable resources, but the relative incremental costs of each market design reform remain directionally stable (LSERO, FRM, and PCM increase costs by $370 million per year while BRS increases costs by $420 million per year).
- The “High Gas Price” sensitivity doubles the natural gas price. This sensitivity yields a similar reliability to the Base Case in the Energy-Only scenario (1.36 days per year loss of load

expectation), and the same target reliability (0.1 days per year loss of load expectation) for the LSERO, FRM, PCM, and BRS by design. System costs increase across all design options because of higher fuel prices, but the relative incremental costs of each market design reform remain directionally stable (LSERO, FRM, and PCM increase costs by $530 million per year while BRS increases costs by $380 million per year).

+ A change in the perspective of market equilibrium where resources only need to cover a go-forward "Low Cost of Retention" of $50/kW-yr instead of "Cost of New Entry" of $93.5/kW-yr significantly improves reliability in the Energy-Only scenario relative to the Base Case with a loss of load expectation of 0.47 days per year. System costs decrease across all design options because of lower plant go-forward costs, but the relative incremental costs of each market design reform remain directionally stable (LSERO, FRM, and PCM increase costs by $490 million per year while BRS increases costs by $290 million per year).

Figure 3. Summary of Quantitative Results Under Sensitivities



1.4 Key Findings

▶ Key Quantitative Findings

+ ERCOT's current energy-only market structure does not target a specific reliability standard, leading to a system that does not provide sufficient revenue to resources to achieve the common reliability standard of 0.1 days/yr LOLE. While today's system appears to be close to the 0.1 days/yr benchmark, under market equilibrium conditions in 2026, the Energy-Only (status quo) design results in an LOLE of 1.25 days/yr.
+ There are multiple market mechanisms that can provide the additional revenue needed to achieve higher levels of reliability due to incentives for more dispatchable resources. The Load Serving Entity Reliability Obligation (LSERO), Forward Reliability Market (FRM), Performance Credit Mechanism (PCM), and Backstop Reliability Service (BRS) designs each improve reliability relative to the Energy-Only design, based on the specified LOLE standard of 0.1 days per year. These

mechanisms result in substantially similar incremental costs, representing approximately 2% of total system cost.

- While the LSERO, FRM, PCM, and BRS designs yield similar expected total costs, their impacts on cost *variability* – the potential for costs to vary year to year based on actual system conditions – are significantly different. The LSERO, FRM, and PCM market designs reduce the variability of annual system costs by transitioning from a design that is dependent upon uncertain scarcity pricing to a design that has more stable price signals. By contrast, the BRS design seeks to preserve the volatility characteristic of today's energy-only market.
- The dispatchable energy credit (DEC) mechanism does not yield a material improvement in system reliability and increases system cost. This design rewards resources that enter the market in response to the DEC requirements, in turn reducing revenues to non-DEC-eligible resources. This increases the likelihood that resources that cannot meet the eligibility criteria for DECs will exit the market.
- The relative cost and reliability impacts of each market design remain stable across the "High Renewables", "High Gas Price", and "Low Cost of Retention" sensitivities, indicating that the relative results are robust to a number of key uncertainties on the 2026 system and beyond.

Key Qualitative Findings

- The LSERO and FRM designs provide market mechanisms to achieve a designated reliability standard through investment in new resources and/or retention of existing ones. The designs also include performance penalties which provide resources with strong incentives to perform in real time. Generator revenues are more stable over time relative to the Energy-Only design, which may result in lower financing costs. Both designs require complex *ex ante* resource accreditation mechanisms and long implementation timelines. These designs are equipped to deal with extreme weather events to the extent they can be reflected accurately in the modeling that is performed for reliability need determination and resource accreditation. These designs preserve strong signals for demand-side resources to contribute to reliability, and both designs have significant prior precedent in other U.S. electricity markets.
- The LSERO may be perceived as presenting a risk of allowing generators to exercise market power and challenges to address cost shifts related to load migration that occurs after the close of the forward compliance period. The FRM addresses both of these concerns through (1) the ability of the independent market monitor (IMM) to mitigate generator bids into the centrally-cleared market, and (2) an *ex post* allocation of reliability credit costs among LSEs based on actual consumption during critical hours.
- The PCM design has similar characteristics to the LSERO and FRM but has slightly less complexity because it avoids the need for forward-looking resource accreditation. However, generator revenues are less stable than under the LSERO and FRM. The PCM is also less able to reflect infrequent extreme weather conditions because it is assessed each year based on actual conditions that may not reflect any extreme weather.
- The BRS design constitutes the smallest change to the existing market framework by largely preserving the current energy-only market dynamics and all of the generator incentives that exist in it, including scarcity pricing and the operating reserve demand curve (ORDC). It has low risk of market power and the shortest implementation timeline of any market design that was studied.

Because BRS resources would only be allowed to participate in the energy and ancillary service markets after all generation in ERCOT is exhausted, this limits the competitive market mechanism of this design and results in scarcity pricing when there is not true scarcity on the system. The BRS may also not be consistent with the principles of a competitive market, since it holds generation out of the market and market participants have no ability to avoid the BRS costs through their own resource procurement decisions.

+ The DEC design presents a low and addressable market power risk as well as moderate complexity and potential implementation timeline. However, the DEC design provides for very limited competition among resource types, little incentive for real-time performance during the hours that matter most, and little ability to address risks related to extreme weather events.

1.5 E3 Recommendation

The PUCT requested E3 to provide a recommended course of action for ERCOT market design reform from among the options presented in this report. E3's recommendation, described in more detail in the body of the study, represents E3's independent view and does not necessarily represent the views of the PUCT Commissioners, PUCT Staff, or E3's subcontractors Astrapé Consulting. Under guidance of the Blueprint, E3 did not consider the existing energy-only market structure as a candidate for our recommendation.

Based on the analysis conducted in this study and our broader experience in market design, E3 recommends that ERCOT implement a **Forward Reliability Market (FRM)** market design. Multiple market designs evaluated in this study appear capable of providing an improvement in market signals to ensure reliability in the ERCOT market. The LSERO, FRM, PCM, and BRS designs each yield improvements in reliability under equilibrium conditions at similar incremental costs relative to today's energy-only design. Accordingly, the choice of a recommendation among these designs is, in many respects, a decision to be made on qualitative factors and which design is perceived by the PUCT and stakeholders to be the best fit with Texas' competitive retail and wholesale markets. E3 believes that the creation of a forward reliability product as envisaged by the LSERO or FRM offers a more suitable fit for the market. This belief stems from the following criteria:

+ **Out-of-market reliability solutions – such as the BRS – should be temporary**
+ **Implementation of the PCM entails significant risk because of its novelty**
+ **Reforms that require procurement of a forward reliability product provide more natural year-to-year stability in market outcomes**

The LSERO and FRM market reforms – which both create a forward reliability product – differ mainly in the structure of the market: the LSERO requires individual LSEs to procure their share of total reliability credits through bilateral contracting, whereas the FRM relies upon a centrally cleared auction to procure the requisite quantity of reliability credits. Between these two structures, E3 finds the centrally cleared to be a better fit for Texas' competitive market landscape for several reasons:

+ **A centrally cleared market unlocks powerful tools for market power mitigation**
+ **A centrally cleared market can be more easily integrated into Texas' dynamic retail market**

Should the PUCT ultimately select the FRM as its preferred market reform, E3 recommends the following specific steps in implementation:

- **Develop a specific reliability standard**
- **Implement marginal ELCC accreditation for all resources through a central process**
- **Address extreme weather**
- **Address fuel security issues**
- **Implement a stringent performance assessment program**

2 Introduction

In December 2021, the PUCT released a Phase II Blueprint that commits to certain reforms in the ERCOT market, namely the development of a load-side reliability mechanism, a backstop reliability mechanism, or a combination of the two.[9] The Blueprint outlines a number of principles that should guide the design of each potential reform, reproduced in Table 4 below.

Under the direction of the PUCT, E3 and Astrapé Consulting ("the Consulting Team") analyzed six specific market design reform proposals that are consistent with the mechanisms and principles outlined in the Blueprint. Each market design is listed below and described in detail in Section 3*, Description of Market Design Alternatives*.

- **Load-Serving Entity Reliability Obligation (LSERO)**
- **Forward Reliability Market (FRM)**
- **Performance Credits Mechanism (PCM)**
- **Backstop Reliability Service (BRS)**
- **Dispatchable Energy Credits (DEC)**
- **Dispatchable Energy Credits + Backstop Reliability Service (DEC/BRS Hybrid)**

The study compares each market design to the current status quo "Energy-Only" design. All market designs (Energy-Only and reform proposals) are analyzed inclusive of Phase I enhancement directives that were approved by the PUCT in Phase I of the Blueprint (December 2021). These enhancements include modifications to the operating reserve demand curve (ORDC), creation of a firm fuel product, accelerated implementation of the new ERCOT Contingency Reserve Service (ECRS) ancillary service product, implementation of reforms to the Emergency Response Service (ERS), and implementation of a new Fast Frequency Response Service (FFRS). By incorporating the Phase I enhancements into this analysis, this study measures the incremental impact of additional market design reforms relative to the Phase I reforms.

The analysis in this study focuses on the snapshot year of 2026, a near-term year that was intentionally selected by the Consulting Team as 1) near-term enough that there is relative certainty about expected loads and resources but 2) long-term enough that any potential market design reform could be implemented.

Each market design reform option is evaluated quantitatively and qualitatively. Quantitative results include expected impacts on (1) resource entry and/or exit (MW), (2) system reliability (frequency, duration, and magnitude of load shedding events), and (3) system costs ($/yr). The qualitative assessment includes an evaluation of each market design reform option along several dimensions such as market power risk and provision for competition. A number of additional design decisions are provided for each design option, including pros and cons of each decision.

[9] https://interchange.puc.texas.gov/Documents/52373_336_1180125.PDF.

Table 4. Market Design Principles Outlined in PUCT's Approved Blueprint

LSERO, FRM, PCM, and DEC Principles	BRS Principles
+ Offer economic rewards and provide robust penalties or alternative compliance payments based on a resource's ability to meet established standards (including penalty at cost of new entry for both non-compliance of load and non-performance of generation) + Build on ERCOT's existing Renewable Energy Credit (REC) trading program framework or other existing framework to the extent practicable + Be self-correcting (in a properly functioning market, higher energy prices will incentivize new supply and over time that additional supply will drive energy prices back down to market equilibrium) + Have clear performance standards (incentivize higher performance) + Sizing of the program must be dynamic (e. g., peak net load) + Provide a forward price signal to encourage investment in dispatchable generation resources + Value or qualify resources based on capability + Establish standards that can be regularly tested or certified upon the start of commercial operation + Be proportional to the system need, with dynamic pricing and sizing to ensure reliability needs are met without over-purchasing reserves + Be compatible with ERCOT's robust competitive retail electricity market that provides choice for consumers + Ensure market power concerns are mitigated, especially regarding electric generation companies that also serve retail customers, so that competition and innovation will continue to thrive in the ERCOT market	+ Be sized on a dynamic, flexible basis to meet a specific reliability need (i.e., seasonal net load variability, low-probability/high-impact scenarios) + Include new and existing accredited dispatchable generation resources that are seasonally tested and able to meet specific minimum and maximum start-time and duration requirements + Include robust non-performance penalties and clawback of payment for noncompliance + Deploy generation resources in a manner that does not negatively impact real-time energy prices (i.e., the deployed generation resources will truly serve as a backstop) + Provide a forward price signal through an annual procurement on a seasonal basis to encourage investment in dispatchable generation resources + Include cost allocation to load based on a load ratio share basis that is measured on a coincident net-peak interval basis + Be developed through a framework that would allow maximum expedited implementation by ERCOT + Be analyzed in conjunction with other long-term market design enhancements

3 Description of Market Design Alternatives

Under the direction of the PUCT, the Consulting Team analyzed six specific market design reform proposals that are consistent with the mechanisms and principles outlined in the Blueprint.

+ **Load-Serving Entity Reliability Obligation (LSERO)**
+ **Forward Reliability Market (FRM)**
+ **Performance Credit Mechanism (PCM)**
+ **Backstop Reliability Service (BRS)**
+ **Dispatchable Energy Credits (DEC)**
+ **Dispatchable Energy Credits + Backstop Reliability Service (DEC/BRS Hybrid)**

This section describes each design in further detail, covering the following topics: (1) an overview of the general theory and mechanics behind the design; (2) key design choices and parameters; and (3) expected market dynamics under each design. Other implementation decisions that must be made for each design whose impact cannot be captured in the quantitative analysis are described in more detail in Section 8*, Additional Considerations and Implementation Options*.

Where possible, parameters are harmonized across designs to allow for consistency in comparison. In particular, for all market designs that target a specified reliability standard, this study uses the "one day in ten years" standard (i.e., 0.1 days/year loss of load expectation) that was chosen under the direction of the PUCT. While this study uses a reliability standard of 0.1 days/year, the PUCT has not adopted a formal reliability standard, and in implementing any new market design, the PUCT would need to determine a specific reliability standard. This could entail choosing a specific loss of load expectation standard or a standard defined based on another reliability metric altogether. To aid in evaluating how results may differ under different reliability standards, the reliability outcomes for each market design are reported using other metrics (i.e., loss of load hours and expected unserved energy) that could be used to define a standard. Total costs to consumers would necessarily rise or fall with the stringency of the chosen standard; for instance, a more reliable standard would lead to higher total system costs. More detail on reliability metrics is provided in Section 4.3.1*, Reliability Metrics*.

Table 5 provides a detailed summary of design elements and assumptions across each of the standalone market design reform proposals that were evaluated.

Table 5. Summary of Design Elements Across Market Designs

Element	Load Serving Entity Reliability Obligation: LSERO	Forward Reliability Market: FRM	Performance Credit Mechanism: PCM	Backstop Reliability Service: BRS	Dispatchable Energy Credits: DEC
Primary Market Mechanism	Bilateral procurement of reliability credits by LSEs with mandatory forward showing	Mandatory centrally-cleared forward market for reliability credits	Centralized settlement process for performance credits at end of compliance period	Centrally procured resources	Annual LSE compliance target for DECs as a % of retail load with mandatory compliance filings
Assumed Reliability Standard [1]	LOLE = 0.1 days/year reliability standard	LOLE = 0.1 days/year reliability standard	LOLE = 0.1 days/year reliability standard	LOLE = 0.1 days/year reliability standard	No defined reliability standard
Allocation to LSEs	Load-ratio share during highest risk hours	Load-ratio share during highest risk hours	Load-ratio share during highest risk hours	Load-ratio share during highest risk hours	All LSEs required to procure DECs equal to percentage of their annual sales (2%)
Resource Eligibility	Technology-neutral	Technology-neutral	Technology-neutral	BRS must have the following characteristics: >= 8 hours of duration for 3 consecutive days	DEC-eligible resources must have the following characteristics: • <= 5 min startup • <= 9,000 Btu/kWh heat rate • >= 48 hr duration
Resource Accreditation Methodology	Accreditation based on availability during hours of highest reliability risk (typically peak net load), measured using marginal effective load carrying capability (ELCC)	Accreditation based on availability during hours of highest reliability risk (typically peak net load), measured using marginal effective load carrying capability (ELCC)	Production of PCs based on availability during hours of highest reliability risk (assumed in this study to be 30 hours), typically peak net load	BRS generation is accredited based on resource eligibility (see above)	1 MWh cleared in the energy, regulation up, RRS, or non-spin market from an eligible resource generates 1 DEC
Deployment of Resources	All resources self-commit and offer into energy market	All resources self-commit and offer into energy market	A resource produces a PC by offering into the energy and/or AS market	• BRS resources bid at offer-cap • BRS resources retain margins when dispatched	DEC-eligible resources self-commit and bid into market economically
Performance Incentives	Penalties for non-performance for all participating resources	Penalties for non-performance for all participating resources	Credits awarded based on actual performance	Penalties for non-performance for BRS resources	Credits based on actual performance

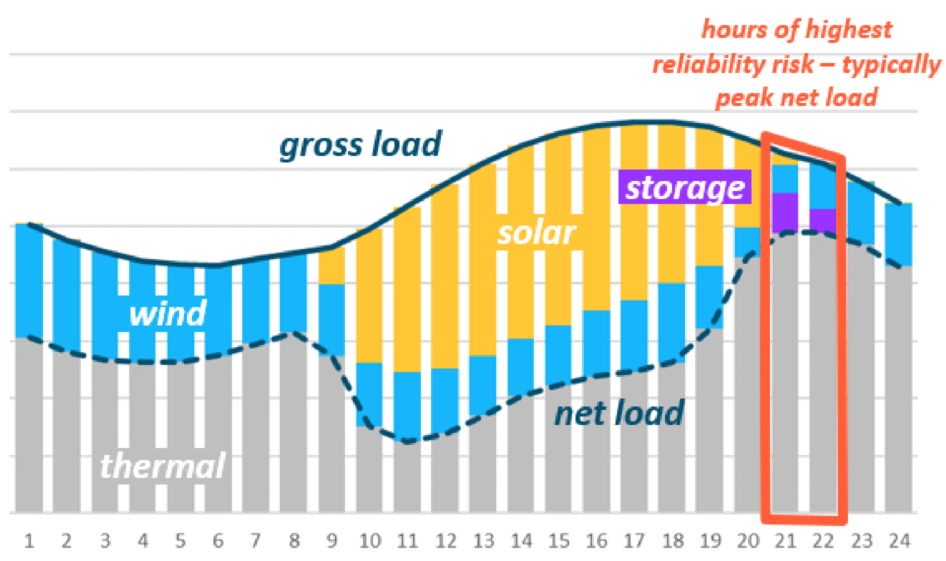
Notes:

1. The analysis in this study applies the industry-standard reliability standard, LOLE of 0.1 days per year across all designs to provide a consistent comparison. Alternative reliability standards could be implemented for any reform; should PUCT move forward with any reform, the selection of an appropriate reliability standard will be an important next step.

Another significant commonality of the LSERO, FRM, PCM, and BRS designs is that they are all tailored to focus on the periods of highest reliability risk, measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with "peak net load."[10] Peak net load is the period of highest electricity demand after accounting for the contributions of wind, solar, and energy storage as illustrated in Figure 4 below. As the penetration of renewables increases, the peak net load will become increasingly disassociated from the gross peak (the period of highest absolute electricity demand) due to the prevalence of variable energy resources (in particular solar) during the summer afternoon gross peak. This is consistent with the mechanics of the energy-only market today that yields scarcity pricing in hours of highest risk which are not necessarily aligned with the gross peak. This overall approach to reliability planning is consistent with a "marginal" framework for calculating a resource's reliability contribution.

An illustration of when hours of highest reliability risk might occur on an illustrative high renewable electricity system is provided in the figure below. It is important to note that these hours are what set the total system reliability requirements. This overall approach is a departure from the traditional paradigm of planning for gross peak metric that is used in many other U.S. capacity market constructs, although it is consistent with the transition to a "marginal" capacity construct as is being implemented by the NYISO[11] market and likely in the ISONE[12] market. It is economically efficient and ultimately minimizes system costs to send economic signals on the basis of highest reliability risk because these are the hours where the system is most constrained.

Figure 4. Illustrative Summer Peak Day Under High Penetrations of Renewables and Storage



[10] To the extent that hours of high reliability risk are due to factors such as thermal outages (planned or unplanned), this would lead to low incremental available operating reserves without necessarily being high net load

[11] https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf.

[12] https://www.iso-ne.com/static-assets/documents/2022/10/a09e_mc_2022_10_12-13_rca_iso_scope_memo.pdf.

3.1 Load-Serving Entity Reliability Obligation (LSERO)

The **Load Serving Entity Reliability Obligation (LSERO)** establishes a system-wide forward requirement for procurement of "reliability credits" and allocates that requirement to LSEs. Reliability credits are assigned to generators by ERCOT based on their expected availability during the periods of highest reliability risk and are procured bilaterally by LSEs, meaning that LSEs will purchase reliability credits through bilateral contracts with generators (not a centrally cleared market). Reliability credit requirements for each LSE are based on their share of system load during periods of highest reliability risk. The requirements assigned to LSEs in an LSERO provide a market signal for investment in new resources and/or retention of existing resources beyond what might be expected in the energy-only market. In this construct, loads and resources are on a level playing field, as load reductions during critical hours count equivalently to resource procurement during these hours. Key attributes of the LSERO market design include:

+ **Forward-looking assessment of system need:** ERCOT conducts a forward-looking assessment of the resources needed to achieve a designated reliability standard, e.g., "one day in ten years" (LOLE of 0.1 days per year).
+ **Resource accreditation:** reliability credits are assigned to each resource in a technology-agnostic manner using a marginal effective load carrying approach (ELCC) approach. ELCC is specific methodological approach to measuring a resource's contribution to system reliability. Marginal ELCC reflects each unit's capability to deliver energy to the system during the anticipated periods of highest reliability risk, measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load. It is an important feature of this design that the total reliability requirement (the forward-looking assessment) and resource accreditation are measured on the same ELCC basis.
+ **Allocation of system need to individual LSEs:** the total system requirement is the sum of the marginal ELCCs assigned to every resource in the accreditation process and reflects the total amount of accredited capacity necessary to achieve the targeted reliability standard. That sum is prospectively allocated among LSEs based on their forecasted share of system load during peak net load periods.
+ **Mandatory forward procurement of reliability credits:** LSEs must procure reliability credits from generators to meet their share of system needs through bilateral transactions.[13] LSEs must show that they have procured sufficient reliability credits on a "prompt" basis, meaning before the beginning of the compliance period.
+ **Generator penalties and incentives for real-time performance:** resources that sell reliability credits incur an obligation to perform during the hours of highest reliability risk and are evaluated based on their performance during these hours. If resources that sold reliability credits fail to

[13] Under a bilateral structure, LSEs that do not procure sufficient reliability credits to meet their obligation are penalized at an alternative compliance price, set at a value that is higher than the expected reliability credit price (e.g., gross cost of new entry). Such a penalty structure will incentivize LSEs to procure sufficient reliability credits to meet their share of system need. Any money collected by ERCOT from deficient LSEs that are penalized at an alternative compliance price would be used to procure emergency backstop generation to ensure that the system achieves target reliability.

perform during the assessed hours, ERCOT applies a financial penalty. The quantitative analysis in this study assumes that resources perform at levels consistent their accreditation, but properly structured incentives are necessary to achieve this – a topic discussed in more detail in Section 8*, Additional Considerations and Implementation Options*. This design component disincentivizes resources from seeking accreditation higher than their actual expected capabilities if they will be held financially accountable to perform at those levels.

Figure 5. General Overview of Load Serving Entity Reliability Obligation (LSERO) Market Design

Prior to Operating Period	During Operating Period	After Operating Period
• LSEs and generators engage in bilateral trading to hedge market exposure • **ERCOT conducts a forward-looking assessment to identify system needs during the peak net load period and assigns reliability credits to resources** • **ERCOT allocates system need among LSEs, who procure reliability credits from generators <u>in a bilateral market</u> to satisfy their individual requirements** • **ERCOT conducts backstop procurement with penalties assessed on non-compliant LSEs**	• LSEs and generators participate in energy & ancillary services markets	• **Generators are assessed penalties resulting from any failures to perform at accredited levels during peak net load period**

Existing processes and settlements under today's energy-only market structure
New processes and settlements introduced in specified market design

Based on the SERVM market outcomes, a natural gas combustion turbine (CT) is the most effective marginal reliability resource that could be added to the system at the lowest cost, and thus would be the expected market response to an economic signal to procure additional resources for reliability. With the increase in generating capacity, scarcity pricing events are less frequent, reducing the energy and ancillary service costs borne by LSEs and energy and ancillary service revenues to generating resources. In order to ensure that resources do not exit the market due to the reduction in revenues, the price for reliability credits would be equal to the *net* cost of new entry of this marginal CT, assuming an efficient market.[14]

[14] The price of reliability credits in this study is denominated in units of effective capacity. This is consistent with the reliability requirement which has been set equal to the effective capacity requirement. Effective capacity is similar but not entirely analogous to the UCAP capacity construct that is used in other U.S. markets. The price of effective capacity for each resource is calculated as the resources' Net CONE ($/kW-yr installed summer) divided by its Effective Capacity. The formulas for these two values are the following:

Net CONE = Gross CONE ($/kW-yr installed summer) – Energy and Ancillary Service Net Revenues ($/kW-yr installed summer);

Effective Capacity = Average Availability in High Reliability Risk Hours (kW) / Installed Summer Capacity (kW).

This means that a resource type such as battery storage could have a lower net CONE than gas CTs – and therefore appear to be cheaper – but also have a lower effective capacity, which would make its cost per effective kW of capacity higher.

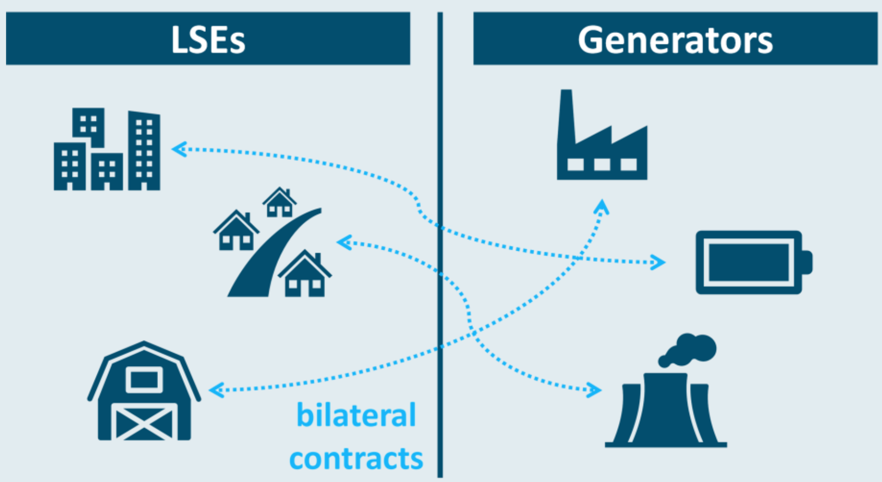
The cost of reliability credits are the additional costs that LSEs would incur in this market design. The net effect of reduced energy and ancillary service costs and increased reliability credit costs yields the total expected cost impact to LSEs.

The LSERO yields expected benefits in the form of improved reliability, specifically, reduced Expected Unserved Energy. This benefit is not included in the quantified benefits, meaning that the quantified benefits are conservative.

In addition to the quantitative assessment, the Consulting Team performed a qualitative assessment of features that do not significantly impact resource entry/exit, reliability, or cost, which are described in Section 8, *Additional Considerations and Implementation Options*.

Overview of Bilateral Market in the LSERO

Under a bilateral procurement framework, ERCOT would assign a reliability requirement to each LSE based on their projected share of system-wide need that is required to achieve target reliability. LSEs would be required to procure sufficient reliability credits from generators, either through ownership of a generating unit or by contracting with a third-party generator. LSEs would then "show" ERCOT that they have procured sufficient reliability credits in advance of the compliance period.



3.2 Forward Reliability Market (FRM)

The **Forward Reliability Market (FRM)** is similar to the LSERO market design but establishes a *centrally-cleared* auction for the forward procurement of reliability credits. Reliability credit requirements for each LSE and their corresponding share of costs are determined at the end of the compliance period based on their actual share of system load during periods of highest reliability risk. The requirements assigned to LSEs and the auction clearing price provide a market signal for investment in new resources and/or retention of existing resources beyond what might be expected in the energy-only market. In this construct, load reductions during critical hours allow LSEs to reduce their reliability requirements, providing an economic signal for demand-side resources to compete with supply-side resources. Key attributes of the FRM design include:

- **Forward-looking assessment of system need:** ERCOT conducts a forward-looking assessment of the resources needed to achieve a designated reliability standard, e.g., "one day in ten years" (LOLE of 0.1 days per year).
- **Resource accreditation:** reliability credits are assigned to each resource in a technology-agnostic manner using a marginal effective load carrying approach (ELCC) approach. ELCC is specific methodological approach to measuring a resource's effective capacity. Marginal ELCC reflects each unit's capability to deliver energy to the system during the anticipated periods of highest reliability risk, measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load. It is an important feature of this design that the total reliability requirement (the forward-looking assessment) and resource accreditation are measured on the same ELCC basis.
- **Sloped demand curve**: ERCOT would develop an administratively-determine sloped demand curve that was set at a level to yield target reliability, to provide for price stability, and to send a signal to the market when excess supply (relative to the reliability requirement) was becoming low.
- **Centrally-cleared forward market for reliability credits:** ERCOT holds an auction to procure reliability credits from generators to meet total needs. The auction would be conducted on a prompt basis, immediately before the start of the compliance period.
- **Allocation of costs to individual LSEs:** the cost of the centralized auction would be retrospectively allocated among LSEs based on their share of system load during the hours of highest reliability risk (e.g., top 30 hours of lowest incremental available operating reserves). This ensures that LSE costs both reflect any potential load migration that occurs after the prompt auction and fully compensates actual realized demand response.
- **Generator penalties and incentives for real-time performance:** Resources that sell reliability credits incur an obligation to perform during the hours of highest reliability risk and are assessed based on their performance during these hours. If resources that were paid for reliability credits fail to perform during the assessed hours, ERCOT would apply a financial penalty. The quantitative analysis in this study assumes that resources perform at levels consistent their accreditation, and properly structured incentives are necessary to achieve this – a topic discussed in more detail in Section *8 Additional Considerations and Implementation Options*. This design component ensures resources will not seek accreditation higher than their actual expected capabilities if they will be held financially accountable to perform at those levels.

Figure 6. General Overview of Forward Reliability Market Design

Prior to Operating Period	During Operating Period	After Operating Period
• LSEs and generators engage in bilateral trading to hedge market exposure • **ERCOT conducts a forward-looking assessment to identify system needs during the net peak period and assigns reliability credits to resources** • **ERCOT conducts a <u>centralized auction for reliability credits</u> to procure the requisite number of credits needed for reliability**	• LSEs and generators participate in energy & ancillary services markets	• **Generators are assessed penalties resulting from any failures to perform at accredited levels during net peak period** • **ERCOT allocates the costs of reliability credits among LSEs based on their actual usage during hours of greatest reliability risk (identified on an *ex post* basis)**

Existing processes and settlements under today's energy-only market structure
New processes and settlements introduced in specified market design

Based on the SERVM market outcomes, a natural gas combustion turbine (CT) is the most effective marginal reliability resource that could be added to the system at the lowest cost, and thus would be the expected market response to an economic signal to procure additional resources for reliability. With the increase in generating capacity, scarcity pricing events are less frequent, reducing the energy and ancillary service costs borne by LSEs and energy and ancillary service revenues to generating resources. In order to ensure that resources do not exit the market due to the reduction in revenues, the price for reliability credits would be equal to the *net* cost of new entry of this marginal CT, assuming an efficient market.[15] The cost of reliability credits are the additional costs that LSEs would incur in this market design. The net effect of these two impacts (reduced energy and ancillary service costs and increased reliability credit costs) yields the total expected cost impact to LSEs.

The FRM yields expected benefits in the form of improved reliability, specifically, reduced Expected Unserved Energy. This benefit is not included in the quantified benefits, meaning that the quantified benefits are conservative.

In addition to the quantitative assessment, the Consulting Team performed a qualitative assessment of features that do not significantly impact resource entry/exit, reliability, or cost, which are described in Section 8.

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[15] The price of reliability credits in this study is denominated in units of effective capacity. This is consistent with the reliability requirement which has been set equal to the effective capacity requirement. Effective capacity is similar but not entirely analogous to the UCAP capacity construct that is used in other U.S. markets. The price of effective capacity for each resource is calculated as the resources' Net CONE ($/kW-yr installed summer) divided by its Effective Capacity. The formulas for these two values are the following:

Net CONE = Gross CONE ($/kW-yr installed summer) – Energy and Ancillary Service Net Revenues ($/kW-yr installed summer);

Effective Capacity = Average Availability in High Reliability Risk Hours (kW) / Installed Summer Capacity (kW).

This means that a resource type such as battery storage could have a lower net CONE than gas CTs – and therefore appear to be cheaper – but also have a lower effective capacity, which would make its cost per effective kW of capacity higher.

Overview of Centralized Market in the FRM

Under a centralized procurement framework, ERCOT would hold a centralized auction for reliability credits. Demand for credits would be based on an administratively determined **demand curve**, designed to procure sufficient reliability resources to meet the target reliability standard. The **supply curve** would be comprised of generator offers and would be tied to the additional revenue generators require to either enter the market or not exit the market. Procurement quantity and price would be determined where supply and demand intersect, and all generators that clear would receive the market clearing price, determined by the bid of the marginal generator.

A centralized procurement framework has the positive attributes that a transparent, system-wide price is visible to all market participants and to the IMM. It also unlocks additional tools for the IMM to mitigate the exertion of market power through limitations on generator offers (see more detail in Section 8.1.8, Market Power Mitigation). The option for a sloped demand curve in a centralized market provides price stability and a price signal that values reliability when the market starts to get "tight" or close to minimum reliability requirements. Additionally, a centralized procurement approach provides the option for ex-post assignment of reliability costs to LSEs based on actual LSE usage as opposed to forecasted LSE usage. This eliminates the potential for LSE under-forecasting. While LSEs would retain the option to bilaterally hedge their reliability obligations outside of the centralized market, a potential drawback of this approach is that some stakeholders view the presence of a centralized market as tempering with a robust bilateral market.

3.3 Performance Credit Mechanism (PCM)

The **Performance Credit Mechanism (PCM)** establishes a requirement for LSEs to purchase "performance credits" (PCs) – earned by generators based on their availability to the system during the hours of highest risk – at a centrally determined clearing price. The PC requirement is a fixed quantity that is determined in advance of the compliance period, while the settlement process occurs retroactively based on the quantity of PCs that were actually produced. PCs are awarded to generators after the close of the compliance period based on a look-back of their availability across a predetermined number of hours of highest reliability risk (e.g., top 30 hours) measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load. When those hours occur is determined retrospectively based on actual system conditions (similar to the hours that determine 4CP). Each LSE's obligation to purchase PCs is based on its pro-rata share of system load during those same hours, and the clearing price of PCs is determined based on an administratively-determined demand curve designed to achieve a target reliability standard (like other designs, an LOLE standard of 0.1 days per year is assumed). In addition to this retroactive settlement process, ERCOT also administers a centrally cleared voluntary forward market for LSEs and generators to exchange PCs to hedge against potential adverse outcomes in the retroactive settlement process; while this forward market is voluntary, generators *must* participate in the forward market in order to qualify to participate in the retroactive PC settlement process.

Key attributes of the PCM design include:

+ **Forward-looking requirement assessment:** ERCOT determines the aggregate availability of resources during the anticipated hours of highest reliability risk (predetermined number of hours, e.g., 30 hours) for a system that meets the 0.1 days/year LOLE reliability standard. This value is represented as an annual MWh number that represents the cumulative availability of all resources across the hours of highest reliability risk.
+ **Sloped demand curve for retroactive settlement process:** The price to procure PCs is based on an administratively-determined demand curve developed by ERCOT that is designed to yield revenues of net-CONE per unit of effective capacity for a system at target reliability. The slope of the demand curve is designed to mitigate annual PC price volatility, recognizing that any given year may produce slightly more or fewer PCs than forecasted. The PCM demand curve would need to be adjusted every year.
+ **Mandatory retroactive settlement process:** After the operating year, PCs are awarded to generators based on a lookback at their availability across the highest risk hours (e.g., 30 hours) of the period; one credit is awarded for each hour in which a megawatt of capacity was offered into the energy or ancillary services market. The price for PCs is settled by cross-referencing the total quantity of PCs awarded with the demand curve. The total cost of PCs (total PCs awarded times the settlement price) is allocated among LSEs based on their pro-rata shares of system demand across the same highest risk hours.
+ **Voluntary centrally-cleared forward PC market:** ERCOT administers a voluntary centrally-cleared forward auction for PCs based on bids to buy PCs from LSEs (demand curve) and offers to sell PCs from generators (supply curve). While the forward market is voluntary, participation in the forward market is a prerequisite for generators to be eligible to produce PCs; however, actual quantities of PCs produced may differ from forward offers – thus it is not expected that this mandatory forward offer requirement would have any impact on the ultimate quantity of PCs that are awarded or on the settlement price. LSE participation in the ERCOT PC market is entirely voluntary.

This design is deliberately structured to achieve the same reliability outcomes as the LSERO and FRM; the key difference is that the LSERO and FRM designs accredit generators *ex-ante* based on their expected contributions to the system during peak net load periods (with penalties/rewards for deviations from this accreditation), whereas the PC design awards performance credits to generators retrospectively based on actual availability during hours of highest reliability risk. The differences between ex-ante accreditation and actual availability during peak net load periods has important qualitative implications that are discussed in more detail in Section *7, Qualitative Review*. An overview of the voluntary forward market and ex post settlement process is provided in Figure 7 below.

Figure 7. General Overview of Performance Credit Market (PCM) Design

Prior to Operating Period	During Operating Period	After Operating Period
• LSEs and generators engage in bilateral trading to hedge market exposure • **ERCOT establishes demand curve for PCs based on forward-looking assessment of system needs during periods of highest risk** • **Generators that wish to produce PCs in residual market submit offers for PCs into voluntary centralized forward market** • **LSEs can submit bids to procure PCs in voluntary centralized forward market**	• LSEs and generators participate in energy & ancillary services markets	• **PCs awarded to generators that submitted forward offers based on real-time availability during periods of highest risk** • **Clearing price for PCs in residual market is determined by demand curve, as supply is a fixed quantity** • **LSEs' obligation to purchase PCs is determined by their load-ratio share during periods of highest risk multiplied by the total quantity of PCs, less any PCs procured in forward market**

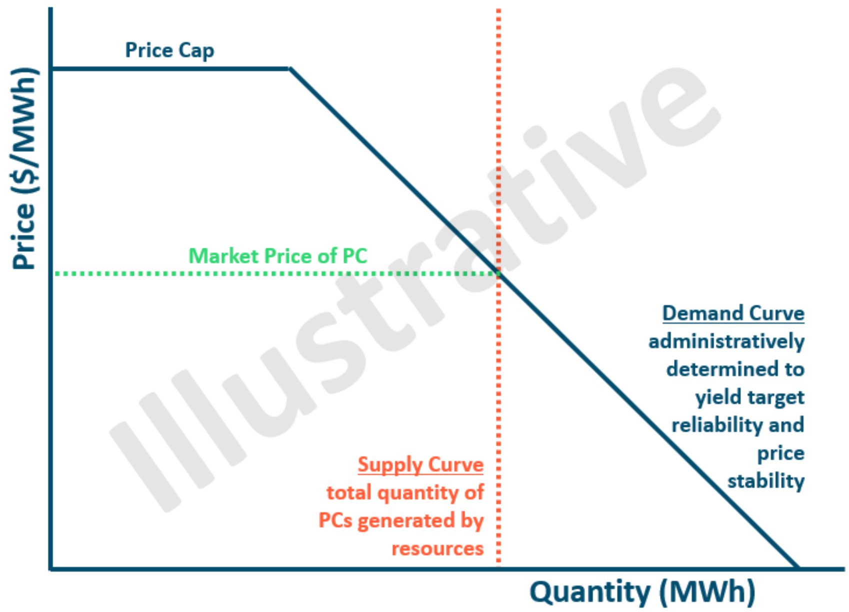
Existing processes and settlements under today's energy-only market structure
New processes and settlements introduced in specified market design

A significant design choice in the implementation of the PCM reform is the shape of the demand curve, which is to be set by ERCOT ahead of the operating year. Because PCs will be awarded to generators retrospectively based on performance during hours of highest reliability risk, the quantity of PCs available during the settlement process will be fixed, and the price will be determined by the corresponding point on the demand curve. The administratively determined demand curve is intended to:

1. Induce entry into the market beyond what would be expected through the current energy-only (status quo) framework;
2. Be "self-correcting" and aligned with economic supply/demand principles; and
3. Provide some level of price stability.

An illustration of this demand curve and price clearing mechanism is illustrated in Figure 8.

Figure 8. Illustrative Performance Credits (PC) Demand and Supply Curve



Because a reliable system must retain resources for availability during extreme events that do not occur every year, the PC requirement will be higher than the sum of energy and operating reserve requirements during critical periods in many years. This provides a more stable revenue stream to generators even in years when scarcity does not manifest in the energy and ancillary services market. The assured annual procurement of PCs provides more stable compensation than the Energy-Only design. ERCOT's determination of the quantity of PCs required provides a means to ensure more resources are available to the system than through the Energy-Only design. With the increase in resources that enter the market through the introduction of this mechanism, scarcity pricing events are less frequent, reducing the energy and ancillary service costs borne by LSEs. LSEs incur additional costs to procure PCs to meet their obligations. The net effect of these two impacts (reduced energy and ancillary service costs and increased performance credit costs) yields the total expected cost impact to LSEs.

In addition to the expected costs, the PCM yields expected benefits in the form of improved reliability, specifically, reduced Expected Unserved Energy. This benefit is not included in the quantified benefits, meaning that the quantified benefits are conservative.

Other design features that are not expected to impact the quantitative results of resource entry/exit, reliability, or system cost are evaluated in Section 8, Additional Considerations and Implementation Options.

Design Comparison: Load Serving Entity Reliability Obligation, Forward Reliability Market, and Performance Credit Mechanism

While all three designs require LSEs to procure credits based on generation availability during hours of highest reliability risk (typically peak net load), there are key differences:

- In the FRM and LSERO, generators receive an *ex-ante* accreditation based on their expected contributions to the system during peak net load periods (and are penalized/rewarded for deviations from this accreditation), whereas the PCM awards credits to generators retrospectively based on actual availability during peak net load periods.
- The FRM and LSERO markets clear and establish prices before the operating period (and thus are invariant to actual system conditions during the year) whereas in the PCM the settlement of PCs occurs retrospectively and is and thus dependent on actual system conditions.
- The PCM design necessarily clears in a centralized manner with a sloped demand curve in order to avoid price formation that would clear at $0/MWh for any system with PC production that exceeds the target or a price at a regulated price cap for any system with PC production that does not meet the target. The FRM features a similar sloped demand curve in the forward auction that modulates the price and quantity of reliability credits procured based on scarcity. The LSERO is entirely bilateral and therefore has no administratively determined demand curve.

3.4 Backstop Reliability Service (BRS)

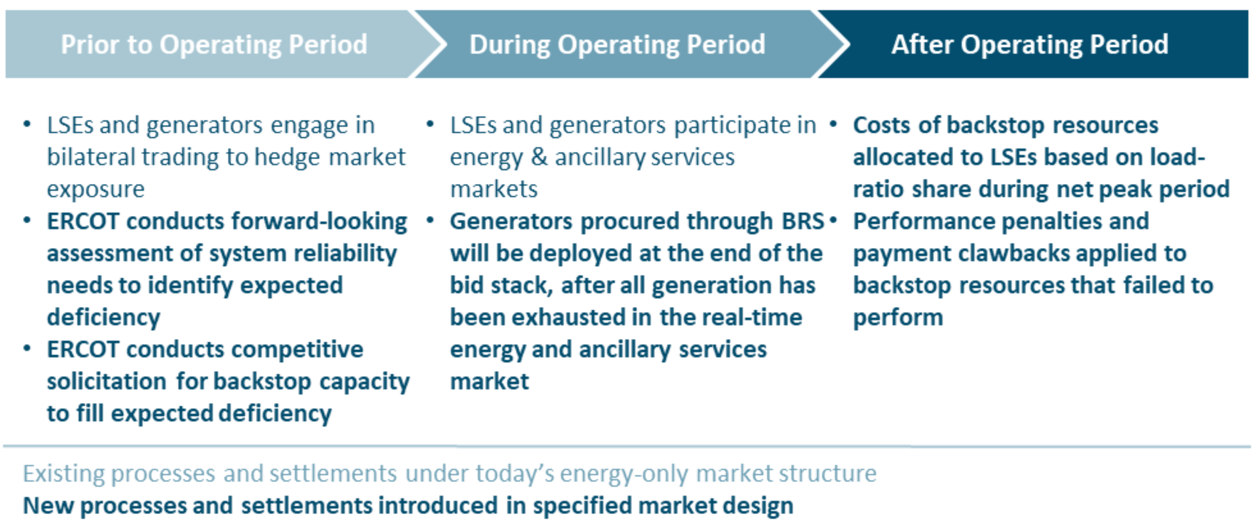
The **Backstop Reliability Service (BRS)** authorizes ERCOT to procure backstop resources needed to ensure that a sufficient quantity of generation is available to meet a specified reliability standard, e.g., LOLE of 0.1 days per year). A BRS resource is one that can only be deployed when ERCOT is in physical scarcity (i.e. when non-BRS resources in the real-time ERCOT market are incapable of meeting aggregate power demand).[16] Based on specifications provided by the PUCT, in order to qualify for consideration as a backstop resource, a generator must demonstrate the capability to dispatch for eight or more consecutive hours for three consecutive days. This study assumes that natural gas CTs are capable of providing this service but does not assume (based on direction from the PUCT) that these generators need to be equipped with supplies of firm fuel to provide this service. Contracting occurs between ERCOT and individual generators, and the cost of procurement is allocated to LSEs based on their load-ratio share during the hours of highest reliability risk, measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load. Key attributes of the BRS market design include:

[16] To avoid any impacts on the price signals present in the energy-only market and ensure the same energy price formation as the current Energy-Only market design, backstop generators are required to bid into the market at the high system-wide offer cap ($5,000/MWh).

- **Forward-looking assessment of system need:** the BRS design requires ERCOT to conduct regular forward-looking assessments of the expected reliability of the system to identify any anticipated shortfalls by comparing expected loads and resources to the specified reliability standard, e.g., LOLE of 0.1 days per year.
- **Forward procurement of backstop resources:** to fill the identified need, ERCOT conducts a competitive solicitation for eligible backstop resources with options for either a "pay-as-bid" or "single clearing price" procurement mechanism.
- **Penalties and incentives for real-time performance:** BRS resources that contract with ERCOT are required to perform when called upon, with financial penalties and payment clawback for non-performance. Additionally, BRS resources will keep the net revenues they make when called upon, giving them a real-time incentive to generate as much as possible when allowed to participate.
- **Allocation of BRS resource costs to LSEs:** after the period, the costs of resources procured through the backstop mechanism are allocated to LSEs based on a retrospective assessment of their load-ratio share during the hours of highest reliability risk, typically aligned with peak net load hours.

These new processes required in the implementation of the BRS design are illustrated in Figure 9.

Figure 9. General Overview of Backstop Reliability Service (BRS) Market Design



Based on the SERVM model results, the marginal BRS resource is a natural gas CT, meaning that this is the lowest net cost effective capacity backstop resource. The Consulting Team assumes a single clearing price at the opportunity cost of foregone revenues in the energy market which is equal to the cost of new entry (true by definition in an energy-only system in equilibrium) minus expected revenues from dispatching at when the system has no more available capacity to meet load (by design, BRS resources are allowed to keep margins earned in energy market when dispatched as the last resource in the generation stack). The allocated costs of backstop resources are the additional costs that LSEs would incur in this market design.

In addition to the expected costs, the BRS yields expected benefits in the form of improved reliability, specifically, reduced Expected Unserved Energy. This benefit is not included in the quantified benefits, meaning that the quantified benefits are conservative.

Other design features that are not expected to impact the quantitative results of resource entry/exit, reliability, or system cost are evaluated in Section 8, *Additional Considerations and Implementation Options*.

3.5 Dispatchable Energy Credits (DECs)

The **Dispatchable Energy Credit (DEC)** market design establishes an annual requirement for each LSE to procure credits produced by eligible dispatchable resources. The LSE-specific annual requirement for DECs is intended to incentivize investment in new flexible generation resources that meet specified eligibility criteria. Based on specifications provided by the PUCT, the DEC design has the following features:

- **Selection of criteria for DEC eligibility:** To qualify as an eligible resource, a generator must have the following characteristics: a start time of 5 minutes or less, a net heat rate below 9,000 LHV Btu/kWh, and an ability to generate for a sustained period of at least 48 hours.
- **DEC production criteria:** An eligible resource produces one DEC (denominated in MWh) when it clears in the energy, regulation up, responsive reserve service, or non-spin market between the hours of 6pm and 10pm in any day of the year.
- **Determination of DEC procurement targets:** The strict criteria for resource eligibility, coupled with the narrow time window for DEC generation, necessitate that the annual requirement for DECs reflect a relatively small share of system loads. For the purposes of this study, DEC requirements for each LSE are assumed to be equal to 2% of annual MWh load. This level would require roughly 10% of system needs (energy and ancillary services) during the 4-hour time window to be served by DEC eligible resources. This requirement is approximately based on the total quantity of DECs that could be produced by the incremental quantity of dispatchable resources that would be procured by the LSERO, FRM, PCM, or BRS market designs, relative to the Energy-Only market design.
- **Bilateral trading of DECs between generators and LSEs:** LSEs transact bilaterally with DEC-eligible generators to procure DECs. These transactions may occur before, during, or after the operating period.
- **Compliance showing of DEC procurement by LSEs:** at the end of the operating period, LSEs make a formal compliance showing to retire DECs equal to their annual procurement target, with a limited banking or borrowing feature to smooth year-to-year variability.

Figure 10. General Overview of Dispatchable Energy Credits (DECs) Market Design

Prior to Operating Period	During Operating Period	After Operating Period
• LSEs and generators engage in bilateral trading to hedge market exposure • **PUCT establishes annual compliance requirement for DECs at level designed to encourage new entry** • **LSEs have option to contract with eligible resources for DECs produced in operations**	• LSEs and generators participate in energy & ancillary services markets • **DEC-eligible resources alter bids into energy market based on expected revenue from DEC generation** • **LSEs buy and sell DECs as needed**	• **LSEs buy and sell DECs as needed** • **LSEs retire DECs needed to meet annual compliance requirements, demonstrated through a showing to the PUCT**

Existing processes and settlements under today's energy-only market structure
New processes and settlements introduced in specified market design

The implementation of a DEC program would have several impacts on market dynamics in ERCOT:

+ Much like existing state Renewable Portfolio Standard (RPS) policies, the requirements assigned to LSEs in a DEC framework would encourage investment in resources that meet the specified criteria. Because of the strict eligibility criteria, few technologies would qualify for eligibility (most likely aeroderivative CTs and reciprocating engines). Notably, the eligibility criteria would exclude frame CTs – generally considered the lowest-cost option for capacity – due to their low efficiency. The entry of these new DEC-eligible resources would cause the frequency of scarcity pricing events to decrease.
+ The ability of DEC-eligible resources to earn revenues outside of energy and ancillary services markets when dispatched would encourage them to bid into those markets below their short-run marginal costs to ensure that they are preferentially dispatched and receive a DEC payment. This alters the merit order of the generation stack (the order in which resources are dispatched), leading to DEC-eligible resources dispatching before lower marginal-cost resources and suppressing market prices.
+ The combination of reduced frequency of scarcity pricing and suppression of energy market prices due to lower bids by DEC-eligible resources creates a stronger signal for ineligible resources to exit the market (or a weaker signal for other ineligible resources to enter the market), with the possible net effect of offsetting some or all of the reliability benefits resulting from the addition of new resources. This dynamic is explored in the quantitative results analysis of this design.

A qualitative evaluation of other aspects of market design that are not expected to impact the market outcomes of resource entry/exit, reliability, or cost is provided in Section 8, *Additional Considerations and Implementation Options*.

Design Comparison: Dispatchable Energy Credits vs. Performance Credit Mechanism

While both the DEC and PCM designs require LSEs to procure credits denominated in MWh to satisfy annual requirements, the two designs have several key differences:

- The DEC design includes stringent criteria for eligibility that would limit DECs to a narrow subset of resources on the system, whereas all generators are eligible to participate in the PCM program
- The DEC requirement is based on a subset of system demand (creating the potential to satisfy this demand at the expense of non-DEC demand), while the PCM requirement is based on total system demand
- DECs are awarded to eligible generators each day of the year during a predefined time window, whereas PCs are awarded retroactively based on performance in a relatively small sample of hours and days
- DECs are transacted bilaterally between LSEs and generators, whereas PCs are exchanged in a centralized settlement process after the operating period
- The requirement for DECs is based on a percentage of each LSE's annual energy sales (and cannot be directly linked to a system reliability standard), whereas the demand curve for PCs is established through an administrative process that links it to expected system reliability requirements and allocation to LSEs is based on their pro-rata shares of system load during the hours of highest reliability risk

3.6 Dispatchable Energy Credit and Backstop Reliability Service Hybrid (DEC/BRS Hybrid)

The **Dispatchable Energy Credit and Backstop Reliability Service Hybrid (DEC/BRS Hybrid)** design combines the reforms described in Section *3.4, Backstop Reliability Service (BRS)* and Section *3.5, Dispatchable Energy Credits (DECs)*. This hybrid establishes a system-wide requirement for the production of DECs (2% of annual load) and allocates that requirement to LSEs using the same eligibility criteria and program design as in the stand-alone DEC scenario. The BRS component of the scenario establishes an ERCOT-procured fleet of backstop generators. The procurement quantity is designed to fill any capacity deficiency from the DEC scenario needed to achieve the specified reliability standard (assumed to be 0.1 days/year LOLE). BRS eligibility and program design are same as in the stand-alone BRS scenario.

DEC requirements assigned to LSEs incentivize a change in system portfolio and operations identically to the standalone DEC scenario. Because backstop resources are the last units in the generation stack and bid in at the price cap, they do not distort energy prices relative to the DEC scenario. LSEs in the DEC/BRS Hybrid design incur costs to procure their share of system DEC requirements and to recover their allocated share of ERCOT-procured BRS resources.

4 Methodology and Assumptions

4.1 Analytical Approach

The Consulting Team analyzed the expected resource entry/exit, reliability, and cost of each market design reform proposal relative to the current status quo "Energy-Only" design. All market designs (Energy-Only and the reform proposals) are analyzed inclusive of Phase I enhancement directives that were approved by the PUCT in December 2021. These reliability reforms include: modifications to the operating reserve demand curve (ORDC), creation of a firm fuel product, accelerated implementation of the new ERCOT Contingency Reserve Service (ECRS) ancillary service product, implementation of reforms to the Emergency Response Service (ERS), and implementation of a new Fast Frequency Response Service (FFRS). Thus, this study measures the incremental impact of additional market design reforms relative to Phase I reforms.

This study examines the performance of each market design under market equilibrium conditions during a specified test year. The Consulting Team selected 2026 as the test year because it is 1) near-term enough that there is relative certainty about expected loads and resources but 2) long-term enough that any potential market design reform could be implemented.

4.1.1 SERVM Loss of Load Probability Model

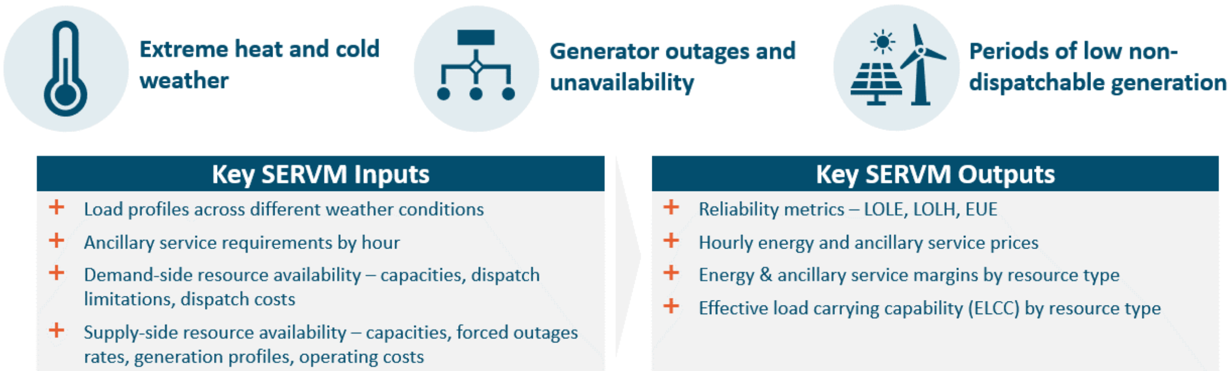
To address questions of system reliability, electricity industry best practice utilizes a loss of load probability (LOLP) modeling framework. For decades, system planners have recognized that planning a reliable generation portfolio requires consideration of both (a) a broad range of possible weather conditions and their associated impacts on load and (b) the likelihood that power plants may be unavailable. Historically, power plant unavailability was driven by traditional resource forced outages but is increasingly also being driven by renewable (wind/sun) availability or use limitations in the case of energy storage. To measure the level of reliability risk associated with a specific portfolio, planners engineered probabilistic approaches to assess the likelihood that supply may be insufficient to meet demand; i.e., simulating the system over many different potential conditions to capture events that may be very rare or infrequent.

E3 subcontracted with Astrapé Consulting to use the "Strategic Energy & Risk Valuation Model" – more commonly referred as the "SERVM" reliability model – to conduct the quantitative analysis. SERVM has been used extensively by ERCOT in prior reserve margin studies. SERVM is a loss-of-load-probability (LOLP) and production cost model that simulates dispatch of the ERCOT system over 1,000 years of different system conditions to identify the most challenging hours to serve load, including system stress conditions explicitly listed in Senate Bill 3[17], namely extreme heat and cold weather, generator outages and

[17] https://capitol.texas.gov/billlookup/text.aspx?LegSess=87R&Bill=SB3

unavailability, and periods of low non-dispatchable generation. An overview of key SERVM inputs and outputs is provided in Figure 11.

Figure 11. Key SERVM Model Inputs and Outputs



The Consulting Team used a proprietary version of the model that previously developed by Astrapé for ERCOT to perform the *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*[18] and made updates to gas prices, expected loads, resources, solar/wind profiles, and new ancillary service requirements for 2026. In previous studies completed for ERCOT, this model has been benchmarked extensively against the performance of the energy-only market to ensure consistency with the operational and market pricing results; additional detail on these calibration and benchmarking efforts can be found in previous studies.[19]

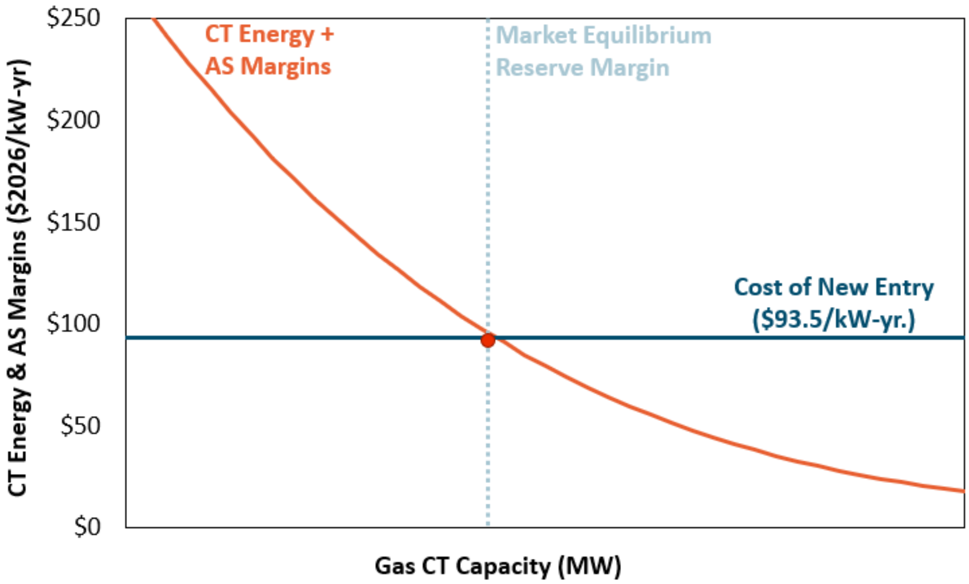
4.1.2 Analysis Under Market Equilibrium Conditions

All market designs are evaluated under a state of **"market equilibrium,"** meaning that generation resources on the system are calibrated to reflect the expected long-term market response to the economic signals provided by each design. The equilibrium condition applied in this study requires that the energy and ancillary service margins (plus any revenue streams enabled by new market mechanisms) for the marginal capacity resource are equal to its cost of new entry (CONE), which is consistent with many prior studies conducted by ERCOT.[20] Based on calculations from the SERVM model, this study determined that a natural gas combustion turbine (CT) was the marginal capacity resource. If CT margins exceed CONE, new gas CT units are added. If CT margins are lower than CONE, coal and gas steam turbine units are removed from the system. The final system reliability and cost results are not sensitive to the exact

[18] https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf.
[19] https://www.astrape.com/wp-content/uploads/2022/03/2014_ERCOT_MERM_Report.pdf; https://www.astrape.com/wp-content/uploads/2022/03/ERCOT_Reserve-Margin-Reliability_Standards_Analysis.pdf; https://www.astrape.com/wp-content/uploads/2022/03/2018_ERCOT_MERM_Report.pdf; https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Responses_to_Questions_Comments_1-15-2021.pdf.
[20] For this study, gas CTs have been determined to be the marginal capacity resource rather than gas combined cycles (CC) given that CTs have lower capital cost and are designed to run at a lower capacity factor which is more aligned with the operations of a higher renewable grid where energy is plentiful in many hours and scarce in others.

breakdown of firm resources (coal vs. gas) in the portfolio but simply the total quantity. An illustration of CT energy and ancillary service margins at different levels of installed CT capacity is shown in Figure 12.[21]

Figure 12. Illustration of Gas CT Margins at Different Levels of Installed Capacity



4.1.3 Future Scenarios Tested

Each of the designs described above is studied under a "Base Case" – a set of assumptions developed by the Consulting Team and the PUCT to represent a plausible state of the world in 2026. However, even over the next four years, many uncertainties exist, and understanding the extent to which the impacts of the market design reforms being contemplated in this process will change under alternative states of the world is critical to making an informed choice. For this reason, this study also evaluates the impact of the market designs under a range of sensitivity assumptions as well. The sensitivities developed in this study are summarized in Table 6.

[21] The process described here results in a partial equilibrium with respect to total capacity and reliability outcomes. In reality, the quantity of other resources on the system would also adjust based on the net margins available to them under each design. Development of a full market equilibrium would require significant additional modeling effort and was beyond the scope of this study.

Table 6. Summary of Scenarios and Sensitivities Analyzed

	Market Designs Evaluated					
Scenario/Sensitivity	**Energy-Only**	**LSERO**	**FRM**	**BRS**	**DEC**	**DEC/BRS Hybrid**
Base Case	✓	✓	✓	✓	✓	✓
High Renewables *(increase in renewables and storage penetration to study whether designs will be self-correcting even as resource mix changes further)*	✓	✓	✓	✓	✗	✗
High Gas Price *(increase in gas price to measure how commodity price uncertainty impacts market design reforms)*	✓	✓	✓	✓	✗	✗
No ORDC *(elimination of ORDC to evaluate how reforms interact with existing ORDC construct)*	✓	✓	✓	✗	✗	✗
Low Cost of Retention *(change in criteria for establishing "market equilibrium" to measure how a change in this assumption impacts key output metrics)*	✓	✓	✓	✓	✗	✗

4.2 Key Assumptions

4.2.1 Load Forecast

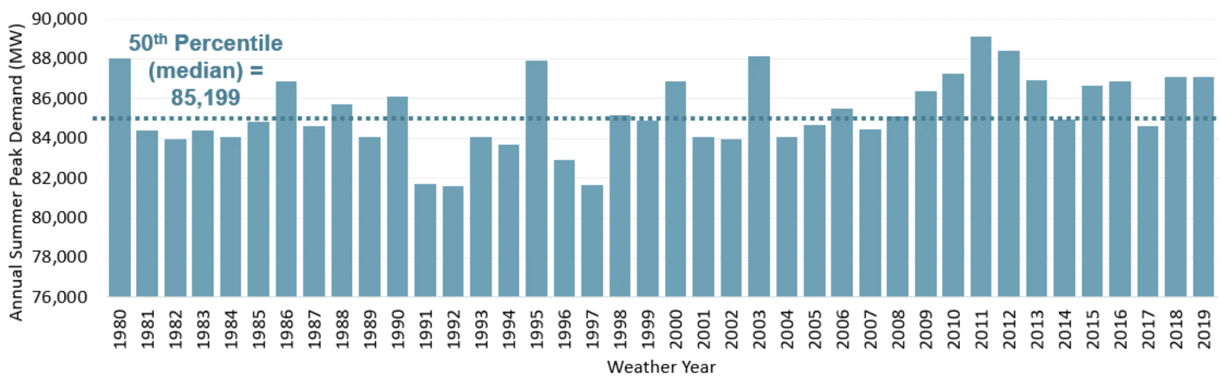
Total annual load is based on ERCOT's 2022 Long-Term Hourly Energy Forecast Study[22], which forecasts 470 TWh in 2026. This represents a 20% growth (77 TWh) from ERCOT's actual load in 2021 (393 TWh). Within the 2026 test year, SERVM incorporates variability to the forecasted load to reflect uncertainty in future conditions due to non-weather factors such as the economy, population, growth in electric vehicles, etc. This variability is represented as upward and downward adjustments to loads by +/-2% and +/-4%, in addition to the Base Case load scenario of 0% adjustment.

Additionally, SERVM represents hourly electricity demand across forty years of historical weather conditions from 1980-2019, providing a rich sample of the distribution of future loads under a range of weather conditions. Figure 13 below illustrates the range of annual peak loads – the highest hourly electrical load in ERCOT for a given year – across all forty historical weather years, all of which occur in the summer. The modeling captures a wider range of potential load patterns across all potential seasons

[22] https://www.ercot.com/files/docs/2022/02/10/2022_LTLF_Hourly.xlsx.

and day-types. Each potential hourly load shape is scaled based on the five total annual electricity load values mentioned in the previous paragraph, creating 200 different load profiles.

Figure 13. Annual/Summer Peak Load Values Across Forty Historical Weather Years Considered



Accounting for both weather and non-weather uncertainty factors, the full range of peak load conditions is shown in Table 7.

Table 7. 2026 Annual Peak Load Percentiles

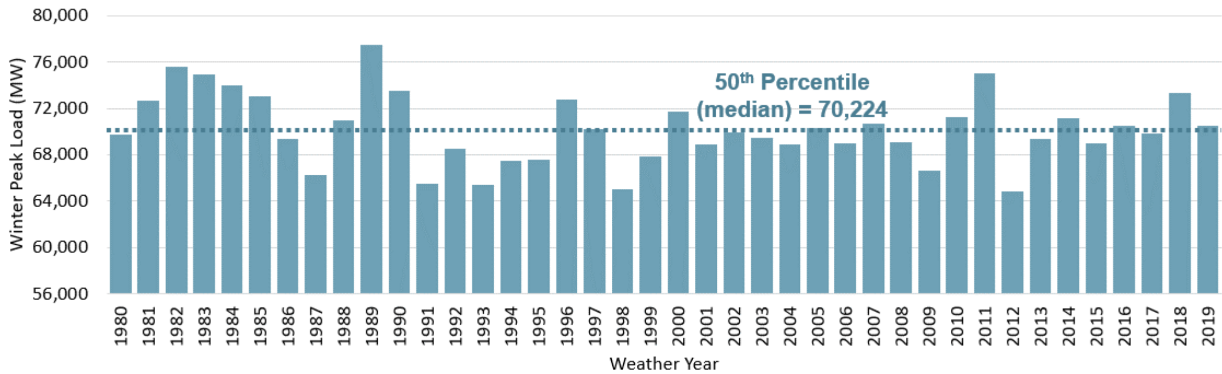
Peak Load Percentile	MW
50th Percentile *(Median)*	**85,199**
80th Percentile *(1-in-5)*	**88,063**
90th Percentile *(1-in-10)*	**89,508**
95th Percentile *(1-in-20)*	**90,420**
99th Percentile *(1-in-100)*	**91,963**
Maximum	**92,723**

This study implicitly assumes that future weather conditions will have the same variability as observed across these 40 historical years. To the extent that future weather conditions are likely to differ significantly from historical conditions, ERCOT should consider incorporating these factors into future analysis and/or any implementation of market reforms.

4.2.1.1 Winter Weather Conditions

The simulated load shapes for the 40 weather years that are incorporated into the SERVM model represent a wide range of potential weather conditions, particularly with respect to summertime hot spells that historically have led to highest peak loads in ERCOT. However, the 40-year lookback period also incorporates winter weather variability to the model, leading to a high volatility in potential winter peak loads, as seen in Figure 14.

Figure 14. Winter Peak Load Values Across Forty Historical Weather Years Considered



The 1980-2019 sample does not include the extreme cold weather event caused by Winter Storm Uri in 2021. Further analysis would be needed to develop a representative long-term load sample that incorporates this type of extreme event at an appropriate probability and to develop a corresponding reliability standard. Such analysis is beyond the scope of this study. In the future, it will be important for ERCOT to incorporate these events into its reliability studies and into any corresponding standard and resource accreditation methodology. Incorporating these events can be expected to affect both the magnitude and frequency of wintertime peak load events in the study sample as well as the accredited and actual performance of resources that are vulnerable to cold-weather related events such as interruptible fuel supply.

4.2.2 Ancillary Services

Ancillary service (AS) products allow system operators to maintain reliability in real-time operations even with load and resource uncertainties, system contingencies, and other unforeseen events. In this study, the Consulting Team worked closely with ERCOT and PUCT staff to develop assumptions for the types and quantities of ancillary service products that would be operational in the ERCOT market by 2026, taking into account the changes prescribed in the Phase I Blueprint. These products differ from today due to the introduction of the ERCOT Contingency Reserve Service (ECRS) and Fast Frequency Response Service (FFRS) products. However, the introduction of these products also leads to the reduction in the requirements of existing products relative to today. The ancillary service assumptions in Table 8 are used across all scenarios.

Table 8. 2026 Average Ancillary Service Procurement

Ancillary Service Product	Average 2026 Requirement (MW)
Regulation Up	500
Responsive Reserve Service (RRS) *Inclusive of fast frequency response service (FFRS)*	2,800
ERCOT Contingency Reserve Service (ECRS)	2,200
Non-Spinning Reserves	2,100
Total Ancillary Service Requirement	**7,600**

Ancillary service requirements vary by hour based on the aggregate real-time uncertainty of load and resource availability. In particular, hours of high renewable ramps such as the evening when the sun is setting can lead to higher AS requirements. Table 9 below shows ERCOT Contingency Reserve Service (ECRS) requirements by month and hour across the entire year. Note that these values average to 2,200 MW across all hours as shown in the table above.

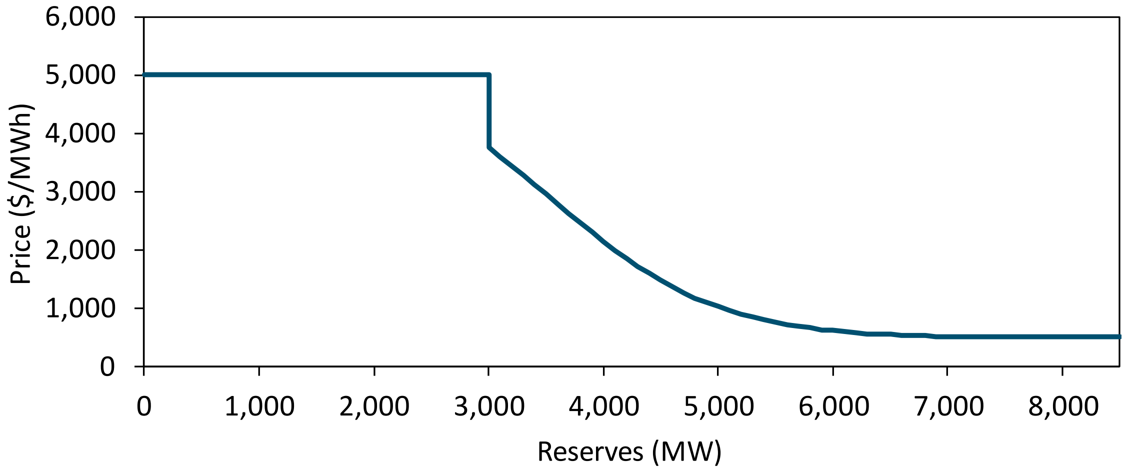
Table 9. 2026 ECRS Procurement by Month and Hour (MW)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	1,266	1,209	1,310	1,308	1,349	1,421	1,577	2,047	1,985	2,431	3,089	2,940	2,667	2,625	2,254	2,471	2,599	2,393	1,654	1,456	1,438	1,479	1,312	1,297
Feb	1,395	1,366	1,460	1,460	1,530	1,557	2,256	2,899	3,133	3,542	2,644	2,450	2,319	2,417	3,249	3,388	3,281	3,009	2,041	1,755	1,815	1,833	1,666	1,482
Mar	1,375	1,247	1,377	1,246	1,356	1,471	1,526	1,716	1,767	1,772	3,119	2,836	2,867	2,677	2,824	3,032	3,202	3,288	2,591	2,385	2,136	1,790	1,443	1,382
Apr	1,365	1,336	1,349	1,381	1,292	1,328	1,612	1,693	1,697	2,359	2,473	2,579	2,786	2,817	3,228	3,159	3,344	3,298	2,785	2,353	2,162	1,889	1,529	1,593
May	1,532	1,507	1,461	1,484	1,515	1,430	1,588	1,721	2,301	2,482	2,758	2,635	2,873	2,827	3,472	3,533	3,819	3,690	2,916	2,794	2,393	2,344	1,861	1,591
Jun	1,509	1,374	1,476	1,471	1,426	1,538	1,732	1,796	2,242	2,335	2,846	2,960	3,013	3,091	2,956	2,978	2,985	2,904	3,157	3,130	3,006	2,667	1,567	1,635
Jul	1,572	1,518	1,556	1,431	1,408	1,417	1,971	2,149	2,823	2,540	2,861	2,902	2,885	2,715	2,444	2,767	2,891	2,764	2,739	2,634	2,317	2,287	1,835	1,718
Aug	1,630	1,622	1,719	1,625	1,595	1,479	1,695	1,897	2,362	2,529	3,078	3,015	3,124	3,068	3,493	3,573	3,648	3,814	3,129	2,984	2,712	2,422	1,897	1,695
Sep	1,727	1,568	1,583	1,551	1,513	1,543	1,688	1,896	2,215	2,838	2,858	2,989	2,833	2,858	3,083	3,166	3,393	2,997	2,251	2,323	2,023	1,876	1,820	1,669
Oct	1,275	1,212	1,357	1,346	1,327	1,423	1,539	1,812	1,707	2,417	1,993	2,317	2,186	2,218	2,488	2,640	2,539	2,727	2,875	1,852	1,737	1,661	1,471	1,420
Nov	1,093	1,150	1,124	1,249	1,277	1,305	1,433	1,668	2,012	2,393	2,730	2,551	2,533	2,427	2,756	2,937	2,609	2,830	1,281	1,384	1,387	1,349	1,277	1,285
Dec	1,459	1,403	1,521	1,653	1,569	1,500	1,721	2,128	2,128	2,911	3,557	3,324	3,046	3,334	3,751	3,459	3,122	3,117	1,382	1,707	1,654	1,678	1,636	1,373

4.2.3 Energy-Only Market Design and Phase I Enhancements

The ERCOT electricity market today is an energy-only construct in which resources earn revenues through real-time provision of energy and ancillary services (although resource owners can voluntarily hedge revenues by signing forward contracts with LSEs). When real-time reserves drop to levels that imply some level of reliability risk, ERCOT administratively increases energy prices through an “operating reserve demand curve” (ORDC). This administrative construct allows resources that are used infrequently to earn revenues in excess of their short-run marginal costs and contribute to recovery of fixed capital costs, a necessary incentive to induce investment. An illustration of the current ERCOT ORDC curve is provided in Figure 15.

Figure 15. ERCOT ORDC Curve Implemented by Phase I of the Blueprint



In December 2021, the PUCT enacted a number of changes to the ERCOT market design through Phase I of the Blueprint – some of which were immediate and some of which will take effect over the next few years. All Phase I changes are expected to be implemented by 2026, the primary year of analysis in this study. A brief summary of select market design enhancements that are applied to all scenarios in this study (Energy-Only status quo and market design reform proposals) is provided below:

- **Updated ORDC:** $5,000/MWh high system-wide offer cap, 3,000 MW minimum contingency level (as shown in Figure 15)
- **Higher ancillary service requirements:** increased Physical Responsive Capability (PRC) targets and additional ancillary service products (ECRS and FFRS) provide ERCOT with enhanced reliability tools
- **Emergency Response Service (ERS):** 925 MW can be deployed by ERCOT at minimum contingency level – *note that a doubling of this value is studied in the "High Renewable" sensitivity case based on a recent increase in ERS budget authorization by the PUCT*
- **Firm fuel product:** assumed to improve fuel availability for thermal resources during cold weather (only forced outages due to extreme cold weather are modeled) – *note that gas system changes under jurisdiction of the Railroad Commission of Texas also contribute to expected better availability of fuel during cold weather going forward*[23]

4.2.4 *Resource Portfolios*

The resource portfolios developed for each market design – including total capacity as well as breakdown by resource type – is built up by the Consulting Team from three components:

[23] https://www.rrc.texas.gov/news/083022-rrc-weatherization-standards/

1. **2022 existing resources:** all existing resources based on the 2022 Seasonal Assessment of Resource Adequacy (SARA) report are included in each portfolio.
2. **CDR additions and retirements:** based on direction provided by PUCT, all portfolios include planned resource additions and retirements between 2022-'26 from ERCOT's May 2022 Capacity, Demand and Reserves (CDR) report.[24] The CDR report shows significant quantities of renewables and energy storage added to the system over this period.
3. **Equilibrium adjustments (design-specific):** Equilibrium is achieved by adjusting the quantity of coal and natural gas resources under each design such that the net margins earned by the marginal capacity resource across all potential market products (energy, ancillary services, or other new market products if applicable) are equal to its cost of new entry (CONE).[25] This study finds that the marginal capacity resource is a natural gas combustion turbine (CT), meaning this is the most economic source of incremental capacity.[26] ***These equilibrium adjustments are an output from, rather than an input to, the analysis, and the quantity of adjustments varies by design.***

Table 10. Resource Assumptions Included in Market Analysis (MW)

Resource Type	Total Installed Summer Capacity, 2022	Net CDR Additions & Retirements, 2022-2026	Equilibrium Adjustments	Total Installed Summer Capacity, 2026
Nuclear	4,973	–	–	**4,973**
Coal	13,568	–	*Adjustments vary by market design*	***Totals vary by market design***
Natural Gas	48,479	+375		
Hydro [1]	372	–	–	**372**
Biomass	163	–	–	**163**
Wind	35,210	+5,394	–	**40,605**
Solar	11,992	+27,335	–	**39,347**
Battery Storage	2,014	+5,397	–	**7,411**
Other [2]	12,134	–	–	**12,134**

Notes:

1. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
2. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

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[24] Report: https://www.ercot.com/files/docs/2022/05/16/CapacityDemandandReservesReport_May2022.pdf; Backup data: https://www.ercot.com/files/docs/2022/05/16/CapacityDemandandReservesReport_May2022.xlsx.

[25] This approach of adjusting CT capacity yields a partial equilibrium with respect to generation capacity and reliability outcomes. A true equilibrium would adjust the quantity of each resource based on its net profits; however, achieving a true equilibrium would require a substantial amount of additional modeling effort and was beyond the scope of this study.

[26] The Consulting Team also analyzed a sensitivity to evaluate an alternative equilibrium perspective based on a generating unit's "low cost of retention" (net margins required to keep the unit online and operating) instead of a "cost of new entry" (net margins required to build a new unit).

4.2.5 Renewable Profiles

Renewable generation profiles in SERVM are represented across a range of different weather conditions using hourly wind and solar generation profiles from weather years 1980-2019 (40 years) developed by UL Services for ERCOT.[27] This dataset provides the model with a rich sample of wind and solar production under a wide range of weather conditions. The same underlying weather data is used across load, wind, and solar profiles for consistency. Figure 16 and Figure 17 show that while wind and solar output average capacity factors are 26% and 40% respectively, actual hourly generation can be significantly higher or lower. All of these potential conditions are captured within the modeling and contribute to both the reliability risks of the system and the ability of these resources to contribute to system reliability requirements.

Figure 16. Solar Generation Daily Profile Scatterplot for Representative Year

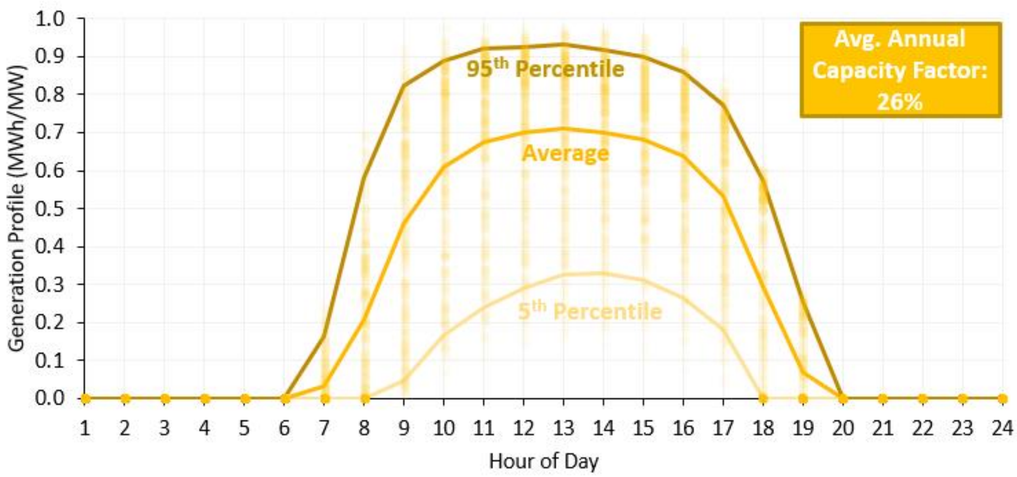
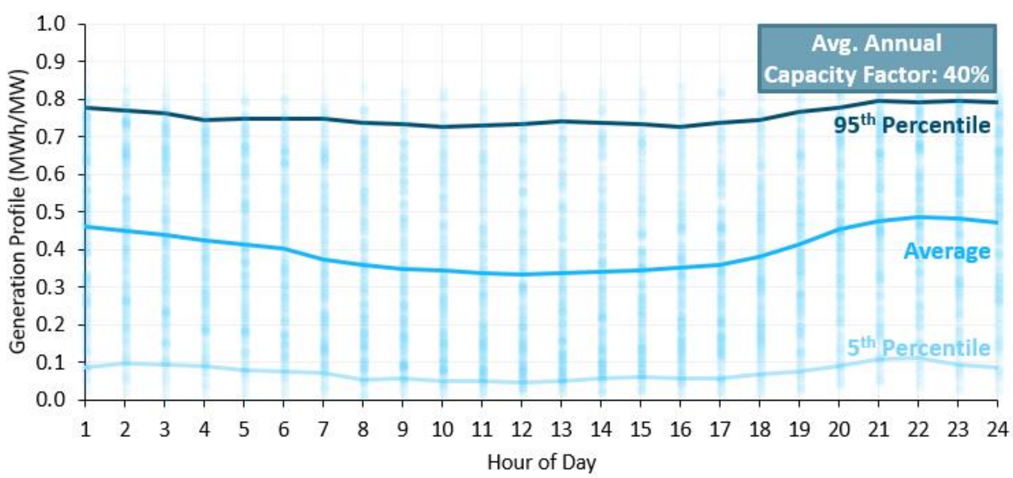


Figure 17. Wind Generation Daily Profile Scatterplot for Representative Year



[27] https://www.ercot.com/files/docs/2021/12/07/Report_ERCOT_1980-2020_WindSolarDGPVGenProfiles.pdf.

The model reflects geographic differences for renewable resources, with the profiles shown above being representations of the aggregate capability of wind and solar in different geographies across the entire state. Specifically, the model includes representations of wind from three different geographic zones – 'coastal wind', 'panhandle wind', and 'other wind' – each with a distinct hourly generation profile and nameplate capacity (based on May 2022 CDR report). The average capacity factor and nameplate capacity for each wind region is shown in below.

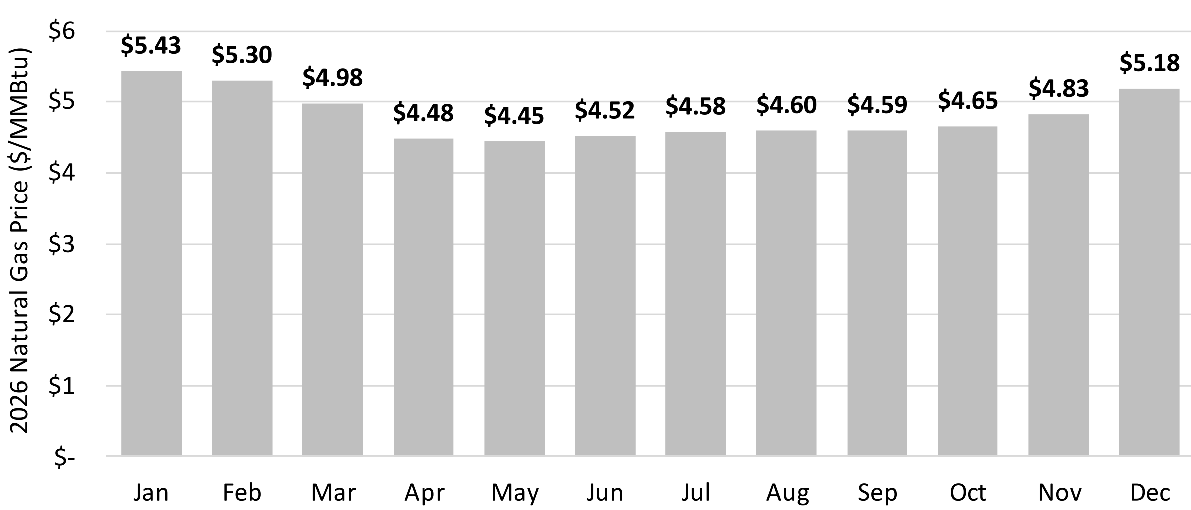
Table 11. 2026 Regional Wind Average Capacity Factor and Summer Capacity

Wind Type	Annual Average Capacity Factor (%)	Total 2026 Summer Capacity (MW)
Coastal Wind	36%	5,900
Panhandle Wind	40%	5,072
Other Wind	42%	29,633

4.2.6 Fuel Prices

Natural gas prices for 2026 are derived from Henry Hub market futures as of August 2022. The price across the entire year averages to $4.80/MMBtu; prices are modeled on a monthly basis as shown in Figure 18.

Figure 18. 2026 Monthly Natural Gas Prices

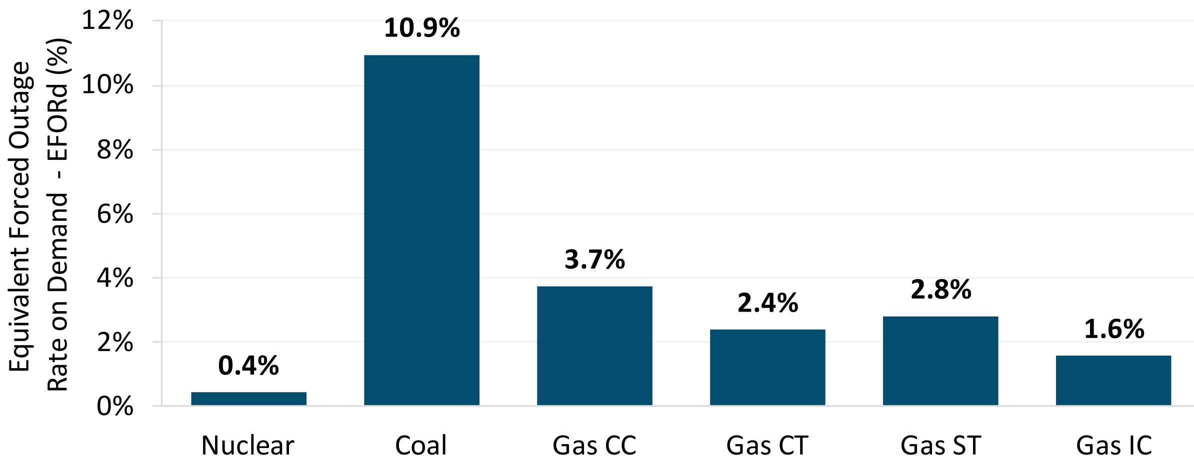


Because the future price of natural gas is both highly uncertain and a major driver of costs in the ERCOT market, this study evaluates the impacts of each market design under a "High Gas Price" sensitivity. In this sensitivity, the 2026 price of natural gas is doubled to nearly $10/MMBtu, reaching a level that aligns closely with the impacts of recent shocks in natural gas markets due to geopolitical instability as well as past historical highs. Analysis of the designs under a range of natural gas price assumptions is important to ensure the choice of any design is robust against this key future uncertainty.

4.2.7 Planned and Unplanned Outages

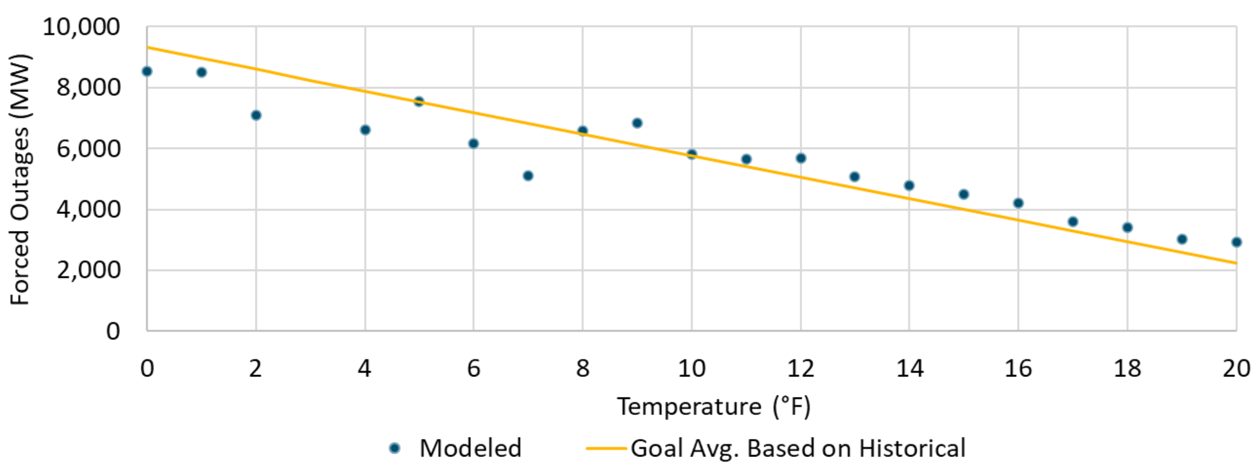
SERVM simulates both planned and unplanned generator outages. Unplanned ("forced") outages are simulated stochastically on a unit-by-unit basis, creating conditions for significantly higher (or lower) than average outages at any given time. Forced outage rates for hydro, solar, wind, and demand response are embedded in the generation/availability profiles of these resources explicitly and are therefore not shown in Figure 19. Storage is also not shown in Figure 19, but was modeled with a 5% Equivalent Forced Outage Rate (EFOR) and dispatched economically.

Figure 19. Capacity-Weighted Equivalent Forced Outage Rate on Demand (EFORd)



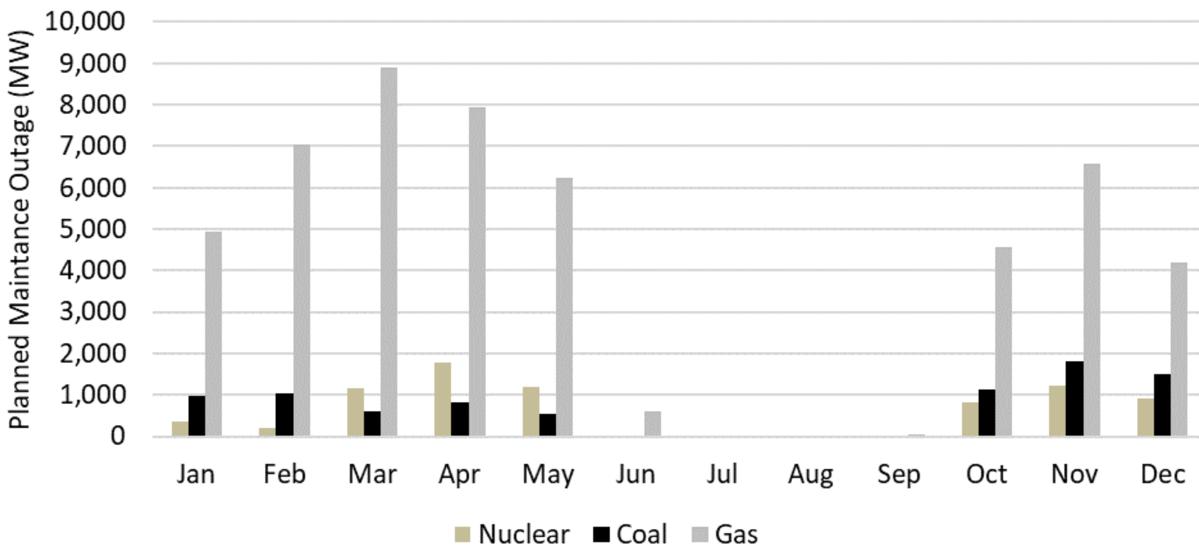
Additionally, unplanned outages are modeled as a function of temperature, reflecting the historical trend of higher outage rates during extreme cold weather representing the higher failure rate of components due to freezing. While this relationship is derived from historical data, it does not include the extreme levels of failures that were observed during Winter Storm Uri in February 2021, as the Consulting Team does not expect the same levels of outage would be observed during similar weather conditions due to improvements that have been made by the PUCT, such as weatherization rules and firm fuel procurement. An illustration of this effect is shown in Figure 20.

Figure 20. Temperature and Forced Outage Relationship



Planned outages are scheduled based on historical practices and reflect generators' imperfect foresight of when scarcity conditions will occur. This is consistent with ERCOT practices and may contribute to reliability risks if high loads occur unexpectedly during shoulder months. Figure 21 shows the average fraction of nuclear, coal, and gas capacity that is on planned outages throughout the different months of the year. Based on historical practices, few planned outages are scheduled during the summer months, where there is generally higher reliability risk, and higher planned outages from October to May. In 2022, the PUCT approved the Maximum Daily Resource Planned Outage Capacity Methodology (MDRPOC) methodology to give ERCOT more control and transparency in the scheduling of planned outages.

Figure 21. Capacity on Planned Outages for Nuclear and Steam Resource Types



4.3 Model Outputs

4.3.1 Reliability Metrics

SERVM simulates the dispatch of the ERCOT system over 1,000 years of different system conditions while introducing potential system conditions including extreme heat and cold weather, generator outages and unavailability, and periods of low non-dispatchable generation. When electricity demand exceeds the ability of the capability of the generation portfolio to deliver electricity, ERCOT must shed load to keep the system in balance. The quantity and characteristics of loss of load events can be measured in several different ways, each of which is described in Table 12 below. This study utilizes all of these metrics to characterize the reliability of different market design reform proposals.

Table 12. Overview of Reliability Metrics

Metric	Units	Notes
Loss of Load Expectation (LOLE)	days/year	This metric provides the total number of days per year in which the system is expected to have loss of load. Any quantity of loss of load within the day counts as "one day" toward this metric. For example, a day with 1 hour or a day with 23 hours would count as "one day". A day with two separate events in the morning and evening would count as "one day". On the other hand, a single event that lasts across two days would count as "two days" toward this metric.
Loss of Load Hours (LOLH)	hours/year	This metric provides the total number of hours per year that the system is expected to have loss of load. This metric is better at capturing the length of events but does not capture the frequency of events like LOLE.
Expected Unserved Energy (EUE)	MWh/year	This metric provides the total quantity of energy per year that the system is expected to not be able to serve due to insufficient resources. This metric is better at capturing the magnitude of events but does not capture the frequency of events like LOLE or the length of events like LOLH.

Under the direction of the PUCT, this report analyzes market designs under a reliability standard of "one day in ten years," equivalent to an LOLE of 0.1 days/year. This means that a system that achieves this level of reliability would expect to experience a load shed event (which may last anywhere from seconds to hours) on one day every ten years.

4.3.2 Cost Metrics

Across the thousands of years of conditions, SERVM simulates resource commitment and dispatch to generate hourly real-time price outputs based on the marginal cost of generation and ORDC adders based on available operating reserves. The dispatch respects unit constraints for all resources, including maximum/minimum capacity, startup times, minimum up/down times, must run designations, and ramp rates. The marginal price in each hour is determined by the cost of the marginal unit and reflects factors such as heat rate and fuel costs, startup costs, variable operations and maintenance costs, and subsidy costs. Using these prices, SERVM dispatches resources and calculates margins by individual resource or class of resources.

The pricing outputs produced by SERVM are used to derive a number of cost-related metrics that provide insights into the impacts of each market design or reform. The key cost metrics quantified in the study are:

+ **Total System Cost:** the total expected cost borne by customers in ERCOT related to energy, ancillary services, and any newly introduced market products. These costs are only inclusive of wholesale electricity market costs and do not include costs associated with the transmission and distribution portion of a customer's bill;
+ **Change in Total System Cost:** the change in total system costs due to the introduction of a new market design product relative to the Total System Cost under the energy-only market;

- **Net Resource Margins:** the net operating margins earned by different types of resources participating in the ERCOT market. This represents the total revenues earned by selling energy, ancillary services, or any newly introduced market product minus the cost to generate that energy in a given year due to short-run costs such as fuel and variable operations and maintenance. These margins contribute to fixed cost recovery including capital expenditures and fixed operations and maintenance expenses.

The total cost metric for each design produced in the study includes the costs (or revenues) associated with ERCOT's energy and ancillary services plus the cost of any other market products that are introduced by that design. While the costs in the energy market are denominated in $/MWh of energy produced in real time, the costs associated with the various new market products are denominated in a number of different units. Each of the new market products and their corresponding units are described in Table 13.

Table 13. Description of new market products introduced by the various market design reforms

Product	Units	Description
Reliability Credits	$/kW-yr	Payments from LSEs to generators made on an **annual basis** per unit of ***accredited capacity*** (expected capacity available during the most critical hours) assigned to each power plant
Performance Credits	$/MWh	Payments from LSEs to generators per unit of **capacity** bid into the energy & AS markets during each of the most critical **hours** of the year
Backstop Reserve Payments	$/kW-yr	Payments from LSEs to generators specifically reserved for BRS purposes made on an **annual basis** per unit of **capacity** reserved for the service
Dispatchable Energy Credits	$/MWh	Payments from LSEs to DEC-eligible generators per unit of **energy or AS** provided to the system during the DEC window (assumed to be 6-10pm for this study)

Under ERCOT's energy-only market structure, costs can vary significantly from year to year based on weather conditions, load and renewable variability, resource outages, and other factors – all of which influence the frequency of scarcity pricing. Thus, while cost metrics are presented on an "expected value" basis – reflecting the average expected cost across the thousands of simulated years in SERVM – this study also examines these costs across the full sample of conditions modeled to illustrate how each design would impact year-to-year variability.

5 Results

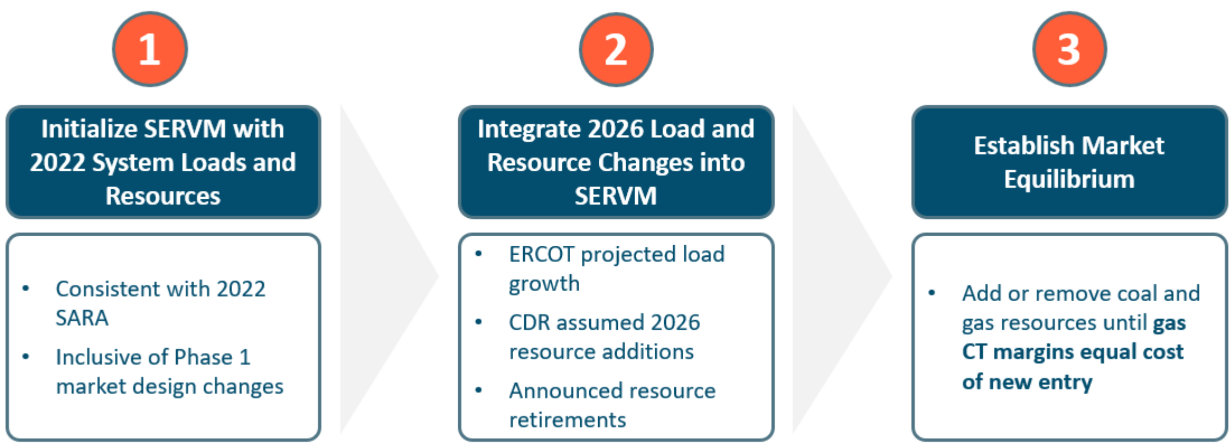
5.1 Energy-Only Design

Analyzing the current energy-only market dynamics under equilibrium conditions in 2026 is necessary to provide a point of comparison for each alternative market design reform proposal. Comparing each reform proposal against the Energy-Only case provides a means to measure how each alternative may impact resource entry/exit, reliability, and cost. The Consulting Team developed this 2026 case by:

1. Initializing the model with 2022 ERCOT loads and resources;
2. Incorporating expected 2026 load and resource changes consistent with ERCOT forecasts and the latest (May 2022) Capacity, Demand, and Reserves (CDR) report; and
3. Establishing market equilibrium in 2026 by adding or removing coal and gas resources until gas CT margins (net revenues) equal the cost of new entry.

This process is illustrated in Figure 22.

Figure 22. Overview of Process to Establish 2026 Energy-Only Case



The resulting portfolio, which includes 2022 existing resources, additions and retirements as reflected in the CDR report, and adjustments needed to achieve equilibrium for the Energy-Only case, is summarized in Table 14. This portfolio reflects a resource mix that is in a state of market equilibrium in 2026.

Table 14. ERCOT resource portfolio in 2026 Energy-Only Design (MW)

Resource Type	Total Installed Summer Capacity, 2022	Net CDR Additions & Retirements, 2022-2026	Equilibrium Adjustments	Total Installed Summer Capacity, 2026
Nuclear	4,973	–	–	**4,973**
Coal	13,568	–	-6,172	**7,396**
Natural Gas	48,479	+375	-5,087	**43,237**
Hydro [1]	372	–	–	**372**
Biomass	163	–	–	**163**
Wind	35,210	+5,394	–	**40,605**
Solar	11,992	+27,335	–	**39,347**
Battery Storage	2,014	+5,397	–	**7,411**
Other [2]	12,134	–	–	**12,134**

Notes:

1. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
2. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

While peak demand is projected to grow from 73,700 MW[28] to 85,200 MW between 2021 and 2026, the resource additions reflected in the CDR – a total of nearly 40,000 MW of solar, wind, and energy storage – yield a system that initially has a surplus of resources relative to equilibrium. Without further adjustments to the resource mix beyond CDR additions and retirements, the "pre-equilibrium" 2026 portfolio would achieve an LOLE of 0.02 days per year, more reliable than the common industry benchmark of 0.1 days per year.

However, the economic pressures on existing resources to exit the market in this "pre-equilibrium" state would also be immense: the low energy and ancillary service prices and infrequent scarcity pricing resulting from the presence of so many resources in the system would result in net margins for natural gas CTs close to $0/kW-yr, far below even the ongoing fixed costs for existing resources. Because this portfolio is so far from market equilibrium, this is not viewed as a plausible outcome of the energy-only market. Adjusting the 2026 portfolio into market equilibrium requires a reduction in 11,560 MW of firm capacity, which the Consulting Team assumed to be split equally between coal and steam gas turbine units. This adjustment process is illustrated in Table 15.[29]

[28] https://www.ercot.com/files/docs/2022/02/24/2022_LTLF_Report.pdf

[29] This result may alternatively be interpreted as a signal that the level of renewable and storage additions provided by the CDR is an unlikely market outcome due to economic factors, as the decline in energy prices that result with their entry may begin to deter further entrants. If this is the case, retention of additional resources will be necessary to maintain reliability in a rapidly changing grid.

Table 15. Results of Calibration Process Used to Attain Condition of Market Equilibrium

Total Equilibrium Adjustment (MW)	Natural Gas CT Net Revenues ($/kW-yr)	LOLE (days/year)
–	~0.0	0.02
(3,820)	4.7	0.04
(5,220)	8.8	0.08
(6,630)	14.7	0.14
(8,040)	25.0	0.25
(10,860)	72.3	0.91
(11,560)	**93.5**	**1.25**

Market Equilibrium

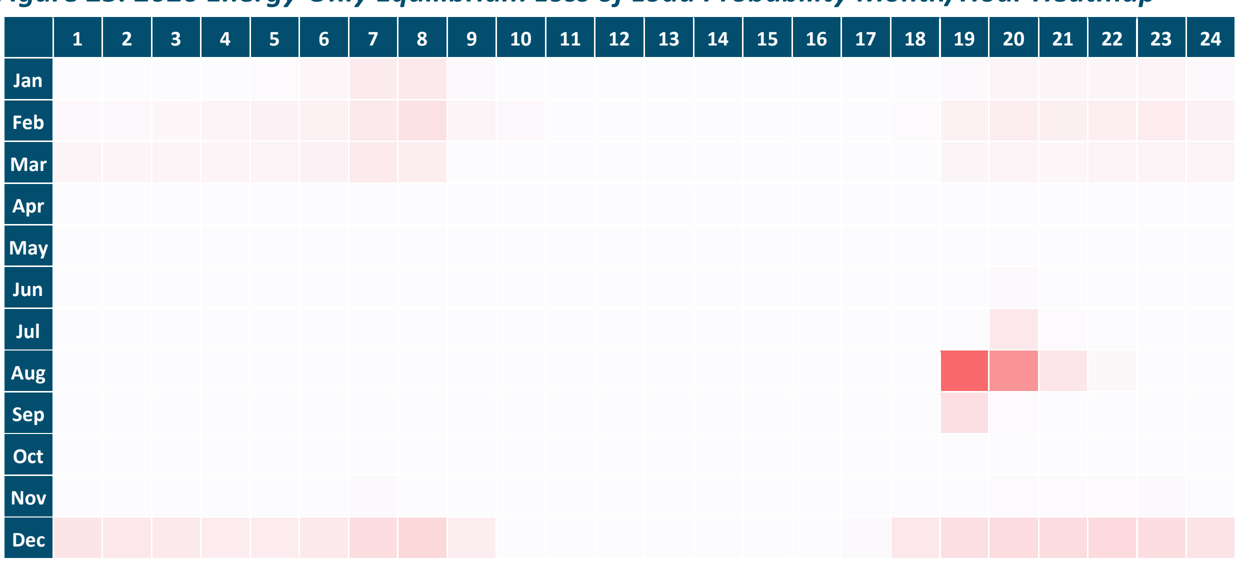
The resulting equilibrium portfolio has a loss of load expectation (LOLE) of 1.25 days/year, significantly higher than the common industry benchmark of 0.1 days/year. The LOLH of the system increases to 3.8 hours/year while the EUE increases to 14,093 MWh per year, as shown in Table 16. This translated into each event shedding about 11,300 MW of load over a 3-hour period.

Table 16. 2026 Energy-Only (Equilibrium) Reliability Statistics

Reliability Metrics	2026 Energy-Only
LOLE *(days/year)*	1.25
LOLH *(hours/year)*	3.8
EUE *(MWh/year)*	14,093

Loss of load events are most likely to occur during summer evenings and winter nights, as illustrated in Figure 23. Nearly all of these high-risk hours occur outside of daylight hours, which aligns with expectations of a system with significant quantities of solar energy.

Figure 23. 2026 Energy-Only Equilibrium Loss of Load Probability Month/Hour Heatmap



While the average year has 1.25 days with loss of load under equilibrium, some years have more, and some years have less events than the average. Sixty-one percent of years do not experience any loss of load, while 39.0% of years have at least one hour of lost load or more. Figure 24 below illustrates the full distribution of number of hours of lost load across all years.

Figure 24. 2026 Energy-Only (Equilibrium) Distribution of Loss of Load Hours per Year

	Loss of Load Hours per Year (hours/year)													
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13+**
Probability	61.0%	6.0%	6.5%	3.0%	2.0%	1.5%	2.0%	1.5%	2.5%	1.0%	0.0%	0.5%	1.5%	11.0%

Comparison to Prior Analyses of Market Equilibrium in ERCOT

In 2021, Astrapé Consulting published *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*, a study commissioned by ERCOT to examine the expected dynamics of the market under equilibrium conditions. Using SERVM and a modeling approach consistent with the techniques used in this study, Astrapé calculated expected reliability metrics in ERCOT under "market equilibrium" conditions based on 2024 loads and resources. This prior analysis suggested that the reliability of a system in market equilibrium would vary as a function of the resource mix:

- In a **2024 Base Case** under market equilibrium conditions, Astrapé's prior study calculated an LOLE of 0.5 days per year.
- In a **2024 High Renewables Case** under market equilibrium conditions, Astrapé's prior study calculated an LOLE of 1.3 days per year.

While assumptions in this current effort include different loads and resources and incorporate the Phase I Blueprint changes, the analysis in this study are generally consistent with this prior work: this study finds that the LOLE is 1.25 days per year under equilibrium conditions in 2026, after significant additions of wind and solar generation, which aligns closely with the previous study's 2024 High Renewables Case. Together, the results of these two studies suggest that as renewables and storage resources are deployed at higher penetrations in the future, the market signals that exist within the Energy-Only market will provide an increasingly weaker signal for investment in resources needed to maintain reliability.

5.2 Alternative Market Designs

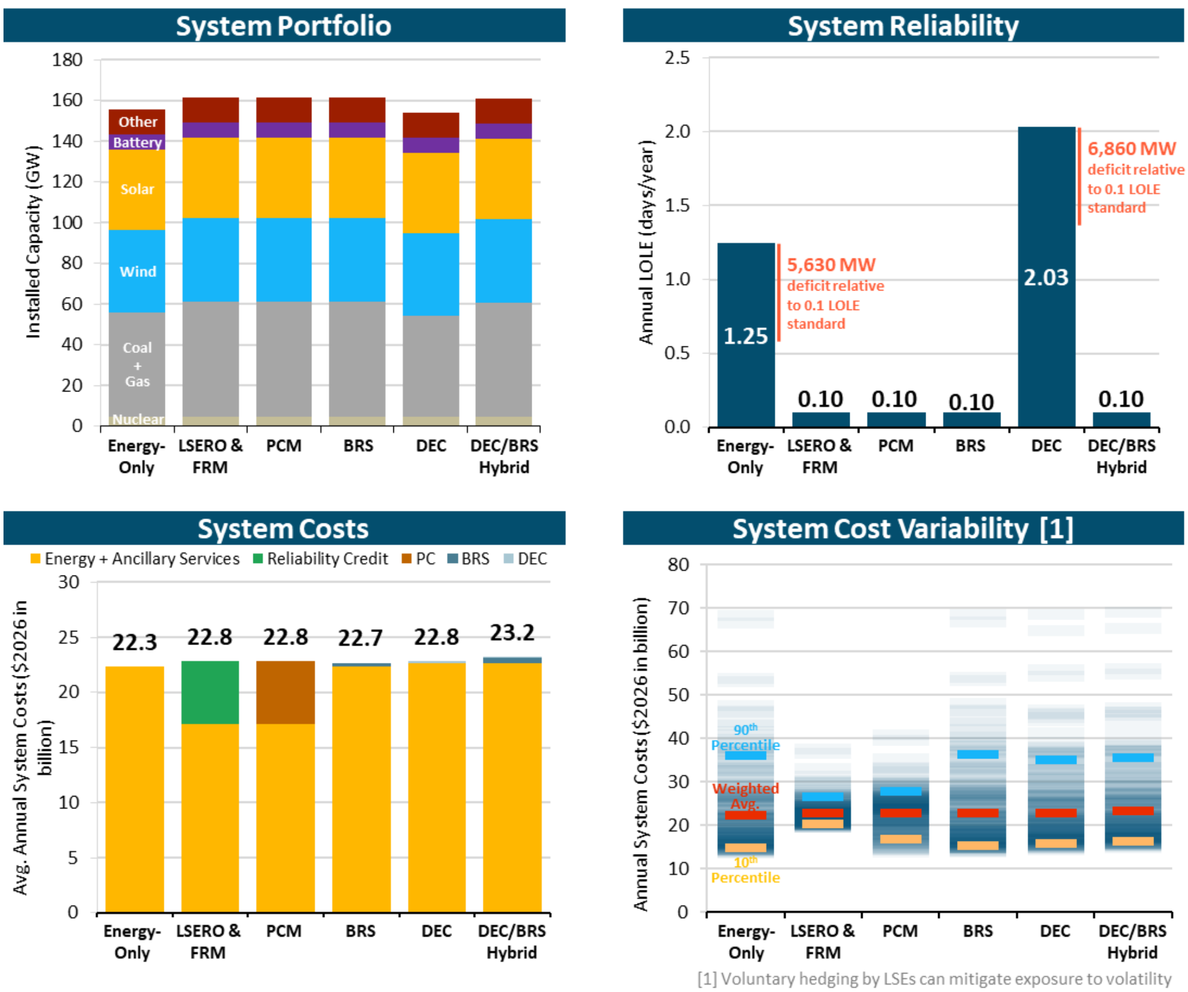
For each market design reform proposal, this study adds the additional market signal or market product to the Energy-Only case and re-establishes equilibrium by adjusting the total system portfolio based on the expected market response to the new economic signals introduced by that design. As with the Energy-Only (status quo) case, a new equilibrium is established by adjusting the quantity of the marginal capacity resource (calculated to be a natural gas CT) on the system such that total CT margins across all potential market products equal the CT cost of new entry (CONE).[30]

For each market design reform proposal in equilibrium, this study produces three key quantitative results:

+ **Resource Portfolio:** total MW of each resource type, including changes relative to the Energy-Only (status quo) scenario
+ **Reliability:** days/year loss of load expectation (LOLE), hours/year, and MWh/year of expected unserved energy
+ **System Cost:** Total annual system cost across all electricity wholesale market products

Figure 25 summarizes the key quantitative results across all scenarios. The remainder of this section describes these results in more detail.

Figure 25. Key Quantitative Results Summary



[30] The Consulting Team also analyzed a sensitivity that establishes an alternative equilibrium based on a "Low Cost of Retention" instead of CONE. See Section 6.4, *Low Cost of Retention Equilibrium*.

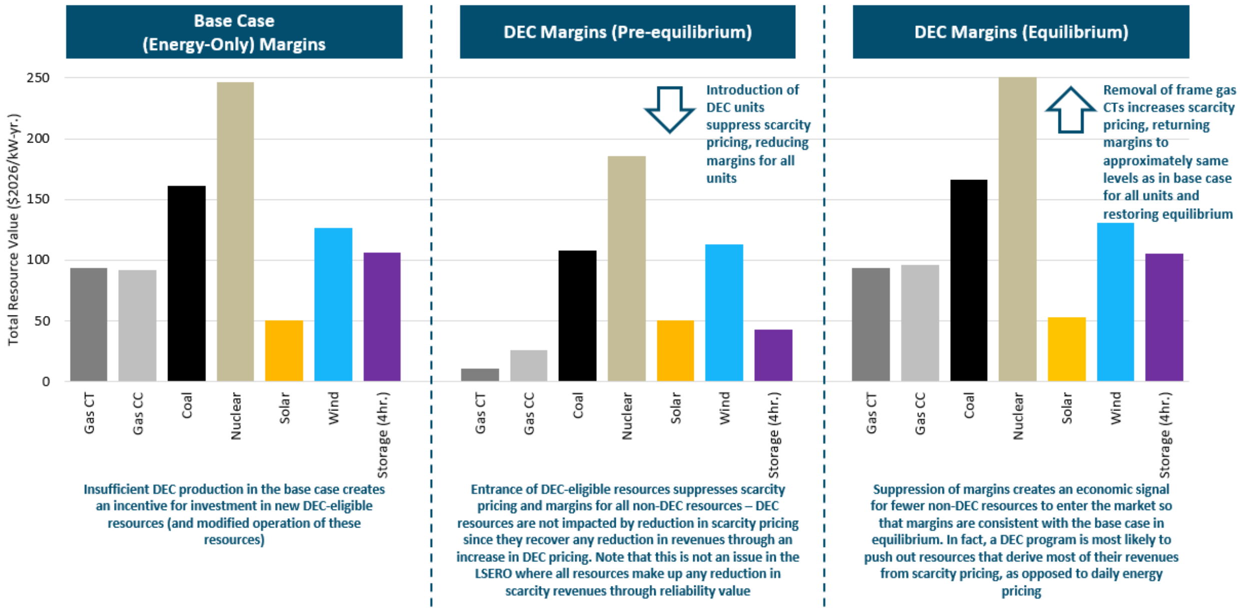
5.2.1 Resource Portfolio

As described above, the resource portfolio for each market design reform proposal is developed by establishing equilibrium conditions by adjusting the total system portfolio based on the expected market response to the new economic signals introduced by that design. A description of the dynamics captured in equilibrium for each market design is provided below. Notably, since the LSERO, FRM, PCM, and BRS designs each target a reliability standard of 0.1 days per year, the resulting resource portfolios under equilibrium are identical, but the market mechanisms that achieve this result differ in each design.

- **LSERO and FRM:** The FRM and LSERO result in the same equilibrium and market outcomes; they differ only in the specific market mechanism. The equilibrium portfolio is developed by adding natural gas CTs – determined to be the least-cost (marginal) source of capacity – to the Energy-Only case until the LOLE is reduced to the target standard of 0.1 days per year. This requires an additional 5,630 MW of natural gas CT capacity. This increase in capacity is supported through a forward reliability credit product that provides sufficient incremental revenues to retain or attract new resources to the market despite a reduction in energy and ancillary service margins that naturally occurs with a larger margin of capacity.
- **PCM:** The PCM design also targets an LOLE of 0.1 days per year, leading to the same requirement of additional 5,630 MW of natural gas capacity relative to the Energy-Only case. Under this design, the incremental revenues available to generators through the mandatory PC settlement provides the economic signal for entry and/or retention of the resources needed.
- **BRS:** The BRS equilibrium portfolio is achieved by assuming procurement of 5,630 MW of natural gas capacity through the backstop mechanism – equal to the amount of capacity needed to improve reliability from the Energy-Only case to the target LOLE standard of 0.1 days/year. Under this design, the resources procured through the BRS mechanism do not impact price signals present in the Energy-Only design, since BRS resources will only be deployed at the end of the bid stack to prevent any impacts to real-time energy price formation for other resources.
- **DEC:** The DEC equilibrium portfolio is developed through a two-step process: first, by calculating the amount of capacity of DEC-eligible aeroderivative natural gas CTs that would be needed to produce 8,600 GWh DECs annually (a number that reflects the difference between 2% of annual load and the expected DEC production from existing eligible resources); and second, after adding the aeroderivative CTs to the portfolio, recalibrating the portfolio to market equilibrium by adjusting the other firm resources in the portfolio. This two-step process is illustrated in Figure 26. The first step yielded an addition of 5,640 MW of new aeroderivative CTs (marginal DEC resource); the second step resulted in the removal of a 7,160 MW of frame CTs relative to the Energy-Only design. The result is a net reduction in 1,600 MW of overall CT capacity.[31]

[31] In the DEC case, aeroderivative CTs do not displace frame CTs on a 1:1 basis is due to two dynamics. First, the high efficiency and flexibility of aeroderivative CTs lead to more frequent conditions where the energy price is lower than the short-run marginal cost of a frame CT. Second, the DEC-eligible aeroderivative CTs bid into energy markets at a level below their short-run marginal cost, further suppressing energy prices available to ineligible resources (see Section 8.4.8, Distortionary Effect on Energy Markets for additional discussion of this phenomenon). In combination, these factors result in a suppression of energy prices that require that, more frame CTs be removed from the system to restore frame CT margins to CONE.

Figure 26. Overview of DEC Equilibrium Methodology



+ **DEC/BRS Hybrid:** The DEC/BRS Hybrid equilibrium portfolio is developed first by starting with the DEC portfolio and determining a 6,860 MW capacity shortfall between this case and what would be necessary to achieve a 0.1 days/year LOLE reliability standard. This gap is larger than under the LSERO or BRS due to market exit of CTs expected under the DEC case. Because the DEC portfolio has a 1,600 MW capacity deficit relative to the Energy-Only portfolio, the 6,860 MW of gas CT resource that would be procured by ERCOT as a backstop service resource results in a net increase of 5,260 MW of CT capacity relative to the Energy-Only portfolio.

Figure 27 summarizes the equilibrium portfolio for each market design reform proposal with the key differences being the amount of natural gas capacity on the system.

Figure 27. System Portfolio by Market Design

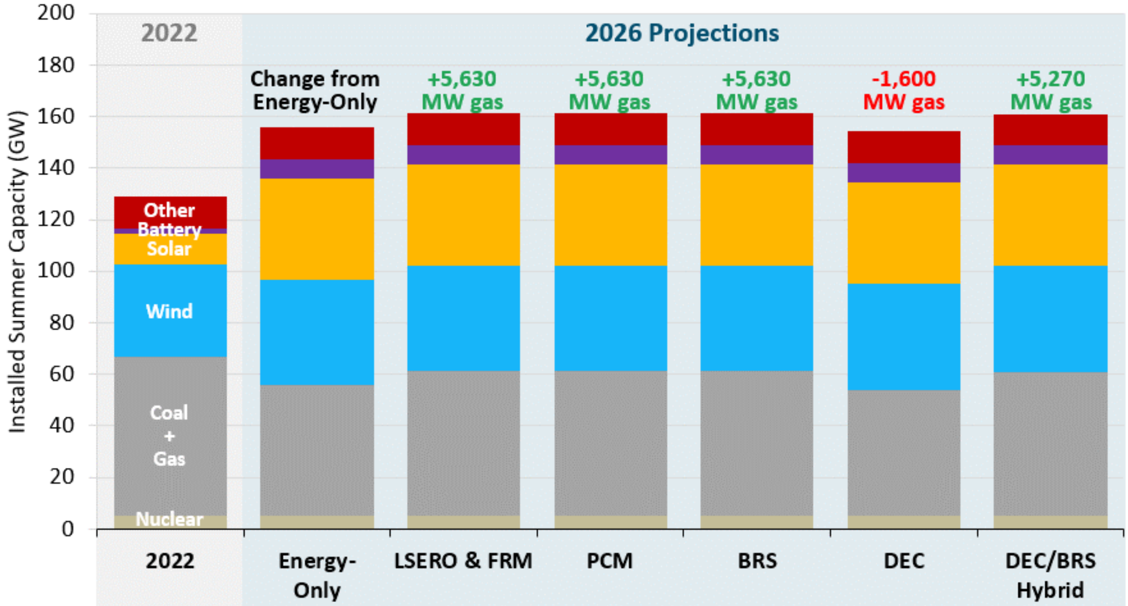


Table 17. Capacity by Resource Type for Base Case (MW)

Resource Type	Total Installed Summer Capacity (MW) [1]					
	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973
Coal	7,396	7,396	7,396	7,396	7,396	7,396
Gas	43,283	48,915	48,915	48,915	41,685	48,549
Hydro [2]	372	372	372	372	372	372
Biomass	163	163	163	163	163	163
Wind	40,605	40,605	40,605	40,605	40,605	40,605
Solar	39,347	39,347	39,347	39,347	39,347	39,347
Batteries	7,411	7,411	7,411	7,411	7,411	7,411
Other [3]	12,134	12,134	12,134	12,134	12,134	12,134

Notes:

1. Values shown in table are exact model outputs; however, for ease of reading, significant figures have been used when referring to these values throughout the body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
3. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

5.2.2 Reliability

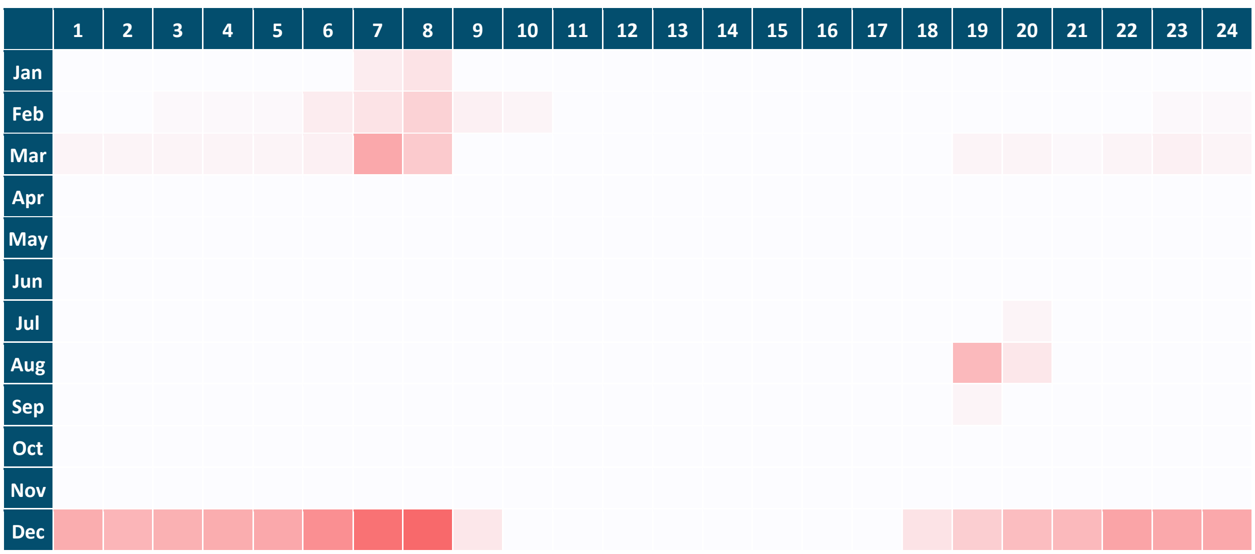
Reliability results are calculated by simulating all system portfolios in the SERVM model. Table 18 provides detailed reliability results across a number of different common metrics for each market design reform proposal. The LSERO, FRM, PCM, BRS, and DEC/BRS Hybrid cases each achieve the 0.1 days/year LOLE standard, which is an improvement relative to the 1.25 days/year LOLE observed in the market equilibrium Energy-Only case. While the frequency of events is much lower under LSERO, FRM, PCM, BRS, and DEC/BRS Hybrid, the length and magnitude of events when they do occur is similar.

Table 18. Detailed Reliability Results by Market Design Reform Proposal in Equilibrium

Reliability Metrics	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
LOLE *(days/year)*	1.25	0.10	0.10	0.10	2.03	0.10
LOLH *(hours/year)*	3.8	0.4	0.4	0.4	5.6	0.4
EUE *(MWh/year)*	14,093	1,632	1,632	1,632	19,053	1,638

The LSERO, FRM, PCM, and BRS designs achieve an identical level of reliability at 0.1 days/year LOLE because they have identical portfolios. Loss of load probability is spread between winter nights and summer evenings, with a heavier weight toward winter as illustrated in Table 19.

Table 19. 2026 LSERO, FRM, PCM, and BRS Equilibrium Loss of Load Probability Month/Hour Heatmap



While there is an average of 0.1 days/year with loss of load, some years have more, and some years have less events than this. Most years (93.5%) of years do not experience any loss of load, while 6.5% of years have at least one hour of lost load or more. Table 20 below illustrates the full distribution of number of hours of lost load across all years.

Table 20. 2026 LSERO, FRM, PCM, and BRS Equilibrium Distribution of Loss of Load Hours per Year

	Loss of Load Hours per Year (hours/year)													
	0	1	2	3	4	5	6	7	8	9	10	11	12	13+
Probability	93.5%	1.5%	0.5%	1.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.5%	0.0%	0.0%	0.5%	1.5%

5.2.3 Cost Metrics

5.2.3.1 Total System Cost

System costs for each market design are calculated by summing the total costs of each product within each market design. A summary of products by market design is provided in Table 21.

Table 21. Products by Market Design

Products	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Energy	✓	✓	✓	✓	✓	✓
Ancillary Service	✓	✓	✓	✓	✓	✓
Reliability Credits	✗	✓	✗	✗	✗	✗
Performance Credits	✗	✗	✓	✗	✗	✗
Dispatchable Energy Credits	✗	✗	✗	✗	✓	✓
Backstop Reserve Costs	✗	✗	✗	✓	✗	✓

Energy and ancillary service prices are direct outputs of the SERVM model, while reliability credit prices, PC prices, DEC prices, and BRS costs are derived from these outputs as described in this section. Table 22 provides average annual system costs for each market design in equilibrium in 2026. The variation in cost among the potential market reforms relative to the Energy-Only design is relatively small: all designs result in an increase in total costs to ERCOT customers of between 2-4%.

Table 22. System Costs by Category for Base Case

	Base Case Costs ($B/yr)					
	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Energy & Ancillary Services	$22.33	$17.12	$17.12	$22.33	$22.67	$22.67
Reliability Credits	–	$5.67	–	–	–	–
Performance Credits	–	–	$5.67	–	–	–
Backstop Service	–	–	–	$0.36	–	$0.43
Dispatchable Energy Credits	–	–	–	–	$0.15	$0.15
Total System Cost	**$22.33**	**$22.79**	**$22.79**	**$22.69**	**$22.82**	**$23.25**
Incremental Reform Cost	**–**	**+$0.46**	**+$0.46**	**+$0.36**	**+$0.49**	**+$0.92**

LSERO and FRM

In an efficient market, the LSERO and FRM mechanisms are expected to have identical market outcomes. The difference between the designs is the specific form of the forward market for reliability certificates – the FRM assumes a mandatory, centrally-cleared auction, whereas LSERO assumes market participants arrive at the same market equilibrium through bilateral trading.

The total system cost of the LSERO and FRM designs, $22.8 billion in 2026, is roughly $460 million higher than the Energy Only case, or a 2% increase. How this cost is broken down among various market products changes significantly under an LSERO and FRM construct: (1) the presence of a larger portfolio of resources than the Energy-Only design reduces the frequency of scarcity pricing, and as a result, the costs borne by consumers directly through the energy and ancillary service markets decreases; and (2) consumers incur a new category of costs as LSEs must purchase reliability credits to meet the requirements of these designs, either bilaterally or through a centrally cleared market.

The LSERO and FRM designs increase capacity on the system relative to the Energy-Only design, suppressing scarcity pricing and thus reducing cost of energy and ancillary services. This simultaneously reduces the energy and ancillary service resource margins. In order to ensure resources enter (or do not exit) the system despite these lower margins, a new “reliability credit” product prospectively compensates resources for their expected availability during hours of high reliability risk. The total cost of reliability credits – roughly $5.7 billion – depends on two primary factors, (1) the total number of credits that must be procured to satisfy system-wide requirements, and (2) the per-unit cost of a reliability credit ($/kW-yr), which is assumed to reach a level consistent with the net cost of the marginal resource for reliability credits – a natural gas CT – under equilibrium conditions.

The reliability requirement is assumed to be set by ERCOT as the total resource requirement during hours of highest reliability risk needed to achieve a 0.1 days/year LOLE standard. These hours would be based on lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load. The Consulting Team calculates the total reliability requirement as 66,940 MW in 2026. This requirement is significantly lower than the 85,000-93,000 MW gross peak because the hours of highest reliability risk no longer occur during the highest gross load periods. Instead, the periods of highest risk typically align with the peak net load, when both load and renewable generation is lower.

In an efficient market in equilibrium, the cost of reliability credits is expected to converge to the net CONE of the marginal resource. This is calculated as show in Table 23, with a final effective reliability credit cost of $85.9/kW-yr.

Table 23. 2026 Reliability Credit Cost Calculation

	CT Gross Cost of New Entry (CONE)	$93.5/kW-yr
–	CT Net Energy Revenues	$10.6/kW-yr
–	CT AS Revenues	$0.4/kW-yr
	CT Net CONE	**$82.5/kW-yr**
/	**CT Effective Capacity**	**96%**
=	**Reliability Credit Cost**	**$85.9/kW-yr**

Each resource in the ERCOT system earns revenues through the sale of reliability credits up to its accredited capacity, which is measured as its marginal effective load carrying capability (ELCC). This framework is internally consistent because the sum of marginal ELCCs for all resources in the system is equivalent to the total reliability requirement when based on hours of highest reliability risk. Marginal ELCC derates all generators relative to their nameplate in a technology-neutral manner, considering all factors that may limit their availability during hours of highest reliability risk: thermal resources are derated based on expected forced outages;[32] renewables are de-rated based on weather variability; and energy-limited resources (storage, hydro, and demand response) are derated based on use and duration limitations.

The total amount paid by LSEs for reliability credits to each resource type is the result of the total effective capacity accredited to that resource type (MW) multiplied by the market price of reliability credits ($85.9/kW-yr, determination of this value in Table 23). This compensation, including the associated effective capacity, is broken down in Table 24.

[32] The availability of fuel for thermal resources is not considered in this analysis; all thermal resources are assumed to have unlimited access to fuel when needed. The potential for fuel limitations is beyond the scope of this analysis. However, fuel supply limitations are an active area of consideration in markets across North America, and ERCOT should address the potential for fuel supply limitations in its implementation of the LSERO or any other prospective reliability standard.

Table 24. LSERO and FRM Reliability Credit Cost Overview

Resource Type[33]	Summer Capacity (MW)	Accredited Capacity (%)[34]	Accredited Capacity (MW)	Reliability Credit Cost ($B/yr)	Reliability Comp. Fraction (%)
Gas CT	12,834	96% [1]	12,364	$1.1	19%
Gas CC	30,687	80%	24,458	$2.1	37%
Gas IC	919	80%	732	$0.1	1%
Steam [2]	16,815	73%	12,249	$1.1	18%
Battery	7,411	34%	2,497	$0.2	4%
Hydro [3]	372	69%	256	~$0.0	~0%
Biomass	163	80%	130	~$0.0	~0%
Solar	39,347	1%	403	~$0.0	1%
Wind	40,605	18%	7,315	$0.6	11%
Other [4]	12,134	47%	5,694	$0.5	9%
Total	**161,286**		**66,098**	**$5.7**	**100%**

Notes:

1. The effective capacity MW is the output of the model and has been normalized to a % value by dividing by summer capacity MW. These values could have been normalized by dividing by winter capacity MW, which would have resulted in lower % values since winter capacity is higher. Because cost results are based on effective capacity MW, the use of summer or winter for % normalization has no impact on final results.
2. "Steam" category includes: coal (7,396 MW), nuclear (4,973 MW), and natural gas steam turbine (4,447 MW).
3. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
4. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

All of the results in the table above are a product of the specific assumptions and scenarios that have been implemented in this study. To the extent that the LSERO or FRM is implemented for an electricity system with a different penetration of wind/solar/storage, the accredited capacity numbers would be different. Additionally, the accredited capacity percentages are calculated by dividing effective capacity (MW) by summer capacity (MW). The use of nameplate winter capacity (which is higher) would have resulted in lower % values but would not have changed results in any way which are solely dependent on effective capacity (MW).

In the 2026 test year, the total reliability credit cost of $5.7 billion is partially offset by the $5.2 billion reduction in energy and ancillary services costs, resulting in a net system cost increase of approximately $460 million per year relative to the Energy-Only design. Partly offsetting that is reduced customer costs due to loss of load. The expected unserved energy (EUE) is reduced in the LSERO and FRM cases by 12,460

[33] Categories selected for accreditation are also subject to change under implementation; accreditation generally occurs at a more granular level than breakdown shown.

[34] Accredited capacity values are highly specific to the various assumptions used in this study, including but not limited to the resource portfolio and planned and forced outages. If LSERO were to be implemented, it is expected that effective capacities will differ given the actual conditions.

MWh per year. At an assumed value of lost load (VOLL) of between $5,000/MWh to $50,000/MWh[35], the total value of reduced loss-of-load could be between $62 million and $620 million per year; this benefit is not included in the total system costs.

PCM

The PCM design also leads to an increase in capacity on the system relative to the Energy-Only design, suppressing scarcity pricing and reducing the cost of energy and ancillary services. As with the LSERO and FRM, this larger amount of capacity simultaneously reduces the energy and ancillary service resource margins. Therefore, the PCM design leads to the same system portfolio and total costs as the LSERO and FRM design, although it uses a different product – the "performance credit" rather than the "reliability credit" – to provide an appropriate economic signal for entry and exit despite the lower energy and ancillary service margins. The total performance credit product cost is equal to the number of credits generated in a year (MWh) multiplied by the cost of a PC ($/MWh).

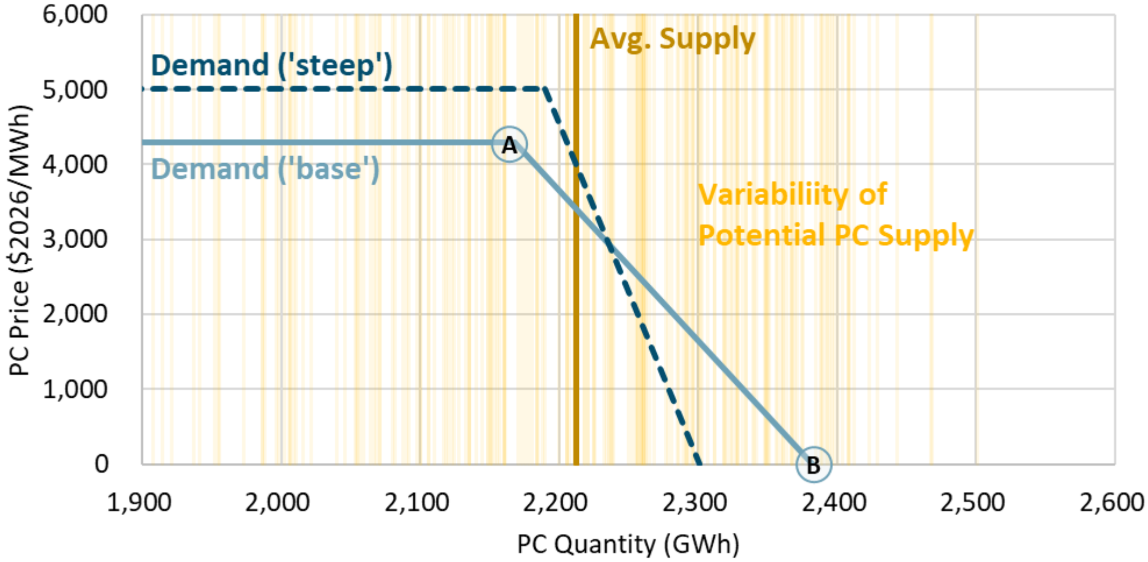
Resources produce PCs in a technology-neutral manner by offering in the real-time market during the 30 hours of highest reliability risk per year.[36] For a given year, the quantity of performance credits produced is a single number, and therefore represents a vertical supply curve. On average across the multiple iterations in the 2026 test year, the number of PCs generated across the 30 hours of highest reliability risk is 2,212 GWh in a system calibrated to achieve 0.1 days/yr LOLE. However, in any individual year, the quantity of PCs generated will deviate from this expected value based on weather conditions, plant outages, and other factors, leading to different vertical supply curves, as shown in Figure 28.

The demand curve is administratively determined to ensure that the system has strong economic incentives to generate the requisite number of PCs needed to achieve the LOLE standard of 0.1 days per year (2,212 GWh in the 2026 test year) while also providing some level of price stability across different years. This incentive is created by providing an annual average compensation to resources for PC production that is the same as the reliability credit compensation in the LSERO and FRM designs, meaning that PCs will compensate resources at an aggregate level of $5.7 billion/yr. Although multiple potential demand curves exist, E3 tested two demand curves – a "base" and a "steep" demand curve – that are shown in Figure 28. Both demand curves meet the reliability requirement at the same average cost but have different inter-annual variability in total annual PC costs; the steeper demand curve will result in more year-to-year cost variability relative to a flatter demand curve.

[35] https://www.ercot.com/files/docs/2013/06/19/ercot_valueoflostload_literaturereviewandmacroeconomic.pdf

[36] There is also a requirement that a resource offer into the voluntary forward market, although it does not have to clear. Because a resource can produce more PCs than it initially offered in the voluntary forward market, the Consulting Team does not expect this requirement to be binding and ultimately impact the quantity of PC production or clearing prices in any way.

Figure 28. Potential PC Supply and Demand ('base' and 'steep') Curves



In the base demand curve, point 'A' on the demand curve represents a price of 1.5 times net-CONE divided by 30 hours ($4,293/MWh[37]) at a quantity of 98% of annual average performance credit production (2,168 GWh) for a system that achieves a 0.1 days/year LOLE standard. This means that the PC price is capped such that generators are not able to collect PC revenues above $4,293/MWh in a given year, however this value is sufficiently higher than the net cost of new entry that it is expected to induce resource entry (or prevent resource retirement). Point 'B' represents the quantity at which PC production greater than this quantity will yield a price of $0/MWh, which for the base demand curve is 108% of the annual average performance credit production (2,383 GWh) for a system that achieves 0.1 days/year LOLE standard. This curve results in an average annual resource compensation of $5.7 billion in the 2026 test year (same as LSERO and FRM).

A steeper demand curve that still meets the reliability requirement can also be utilized, such as the one shown in Figure 28. The steeper curve has a higher price cap and a lower maximum quantity of PC production beyond which the price falls to zero. Since this demand has a shorter section that is sloped, a small change in quantity will lead to proportionately larger changes in price relative to the base demand curve. This means that the inter-annual cost volatility of PC costs / revenues is higher with a steeper demand curve.

The total compensation for performance to each resource type is their annual PC generation multiplied by the market price of performance credits, which varies depending on the year. This compensation, including the associated performance credit generation, is broken down in Table 25.

[37] 1.5 x $85.9/kW-yr / 30 hrs./yr x 1,000 kW/MW = $4,293/MWh.

Table 25. PCM Cost Overview

Resource Type	Summer Capacity (MW)	Performance Credit Production (GWh)	PC Effectiveness (%) [1]	Performance Comp. ($B/yr)	Performance Comp. Fraction (%)
Gas CT	12,834	375	97%	$1.0	18%
Gas CC	30,687	834	91%	$2.2	38%
Gas IC	919	27	96%	$0.1	1%
Steam [2]	16,815	428	85%	$1.1	19%
Battery	7,411	85	38%	$0.2	4%
Hydro [3]	372	7	66%	~$0.0	~0%
Biomass	163	5	94%	~$0.0	~0%
Solar	39,347	20	2%	~$0.0	1%
Wind	40,605	252	21%	$0.6	11%
Other [4]	12,134	179	49%	$0.5	8%
Total	**161,286**	**2,212**		**$5.7**	**100%**

Notes:

1. ”PC Effectiveness (%)” is a measure of the quantity of PCs each type of resource generates measured relative to a “perfect” resource available at full capacity across all critical hours. Note that this is similar – but not exactly equal to – “Accredited Capacity” in the LSERO and FRM designs.
2. “Steam” category includes: coal (7,396 MW), nuclear (4,973 MW), and natural gas steam turbine (4,447 MW).
3. 372 MW represents SERVM’s average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT’s CDR report.
4. “Other” category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

Similar to LSERO and FRM, the $5.7 billion cost to procure PCs in test year 2026 is partially offset by a $5.2 billion decrease in energy and ancillary services costs, resulting in a net system cost increase of approximately $460 million.

BRS

The BRS design results in total consumer costs of $22.7 billion in test year 2026, roughly $360 million higher than the costs of the Energy-Only design. This incremental cost reflects the costs to secure contracts with the BRS resources needed to meet the desired reliability standard. Because these resources are incremental to the Energy-Only design portfolio but withheld from participation until all generation in the real-time energy and ancillary services market is exhausted, these BRS resources are available to improve reliability but still allow for the formation of scarcity pricing in many hours, including hours in which they are dispatching.

The total cost resources procured through the BRS mechanism is the total quantity of backstop resources procured (MW) multiplied by the unit cost of contracting with BRS resources ($/kW-yr). In the 2026 test year, 5,630 MW of additional natural gas CT capacity relative to the Energy-Only design is needed to achieve the 0.1 days/year LOLE reliability standard. The unit cost of BRS is equal to foregone margins in the energy market (i.e., opportunity cost of being held of out of market which in energy-only equilibrium is equal to gross CONE) that a generator would incur to participate as a BRS resource. The BRS design allows BRS generators to retain margins when they are dispatched (bidding at the price cap). Therefore, opportunity costs are only represented as lost margins during non-price cap hours that exceed their marginal cost. The modeling shows that BRS resources are expected to dispatch an average 6 hours/year at the price cap of $5,000/MWh, yielding expected margins of approximately $30/kW-yr. This calculation process illustrating all BRS costs is illustrated below in Table 26.

Table 26. BRS Cost Overview

	BRS CT Gross Cost of New Entry (CONE)	$93.5/kW-yr
–	BRS Net Energy Revenues at Price Cap	$30.6/kW-yr
	BRS Net Cost	**$62.9/kW-yr**
x	BRS Capacity	5,630 MW
	BRS Total Cost	**$355M/yr**

This analysis makes no assumption as to whether the resources contracted through the BRS mechanism are new or existing units, as the Energy-Only market design yields energy and AS margins of gross CONE to both new and existing units. Therefore, there is no difference in their opportunity cost of being held out of the market.

DEC

The DEC design modifies the quantity and type of capacity on the system, relative to the Energy-Only design. The addition of 5,640 MW of new aeroderivative CTs (the marginal DEC resource) is necessary to meet the DEC targets set forth in this design. However, the entry of this quantity of new resource significantly suppresses scarcity pricing for all resources in the market, particularly non-aeroderivative CT resources. This reduction in margins would cause the exit of these resources which would restore scarcity pricing to the market and thus restore resource margins. This dynamic is illustrated in.

Because CTs enter and exit the market up to the point that margins equal gross CONE (same as in Energy-Only design), the frequency of scarcity pricing in this design is similar to that in the Energy-Only case. The key difference in the DEC scenario is the presence of aeroderivative gas turbines, which have a slight cost premium relative to frame gas turbines (assumed in this analysis to be 25%[38]). In order to ensure that these resources enter the market despite their cost premium, a new "dispatchable energy credit" product compensates these resources based on the difference in their total cost and the margins these resources would expect to earn in the energy and ancillary service market. Thus, in addition to energy ancillary services costs, LSEs would incur additional costs to contract with DEC-eligible resources; the total cost resulting from procurement of DECs is equal to the DEC requirement (MWh) multiplied by the DEC price ($/MWh). An overview of these costs is shown in Table 27. The annual costs associated with procurement of DECs ($147 million) represent a relatively small proportion of total system costs.

[38] Levelized costs calculated using E3's Pro Forma tool; Capital cost and operations & maintenance (O&M) costs assumptions based on EIA 2020 "Capital Cost" report: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf (with minor cost modifications based on recent market trends).

Table 27. DEC Cost Overview

Item		Units	Value	Notes
1	Levelized DEC Resource Cost	$/kW-yr	$117	Cost of best-in-class aeroderivative gas turbine; cost estimated by adding a 25% premium over CT CONE ($93.5/kW-yr)
2	DEC Energy + AS Margins	$/kW-yr	$95	Energy and AS net annual revenues (net of production costs) for DEC-eligible units across all hours of the day
3	DEC Price	$/MWh	$15	Levelized DEC Cost (1) minus DEC Energy + AS Margins (2), divided by the number of DEC-eligible hours in a year (4 hrs./day * 365 days/year), normalized for a 5% FOR
4	DEC Requirement	MWh/year	9,400,000	2% of annual load (470 TWh)
5	**Annual DEC Cost**	**$/year**	**$147M**	**Total annual DEC cost: DEC Price (4) multiplied by DEC Requirement (5)**

5.2.3.2 Cost Variability

The costs discussed above represent annual average costs, but costs can vary significantly year-to-year based on a number of different factors, including weather, renewable generation, and generator outages. In the Energy-Only case, while total annual system costs average $22.3 billion per year, annual system costs may range from $14.8 billion (10th percentile) to $36.1 billion (90th percentile) per year, depending on whether a year is mild or extreme.[39] The primary determinant of whether costs fall at the upper or lower end of this range is the presence of scarcity pricing. A mild year with no scarcity pricing will yield costs on the lower end of the range, while an extreme year with significant scarcity pricing will yield costs on the upper end. Figure 29 below illustrates annual cost volatility in the market across each of the different market designs.

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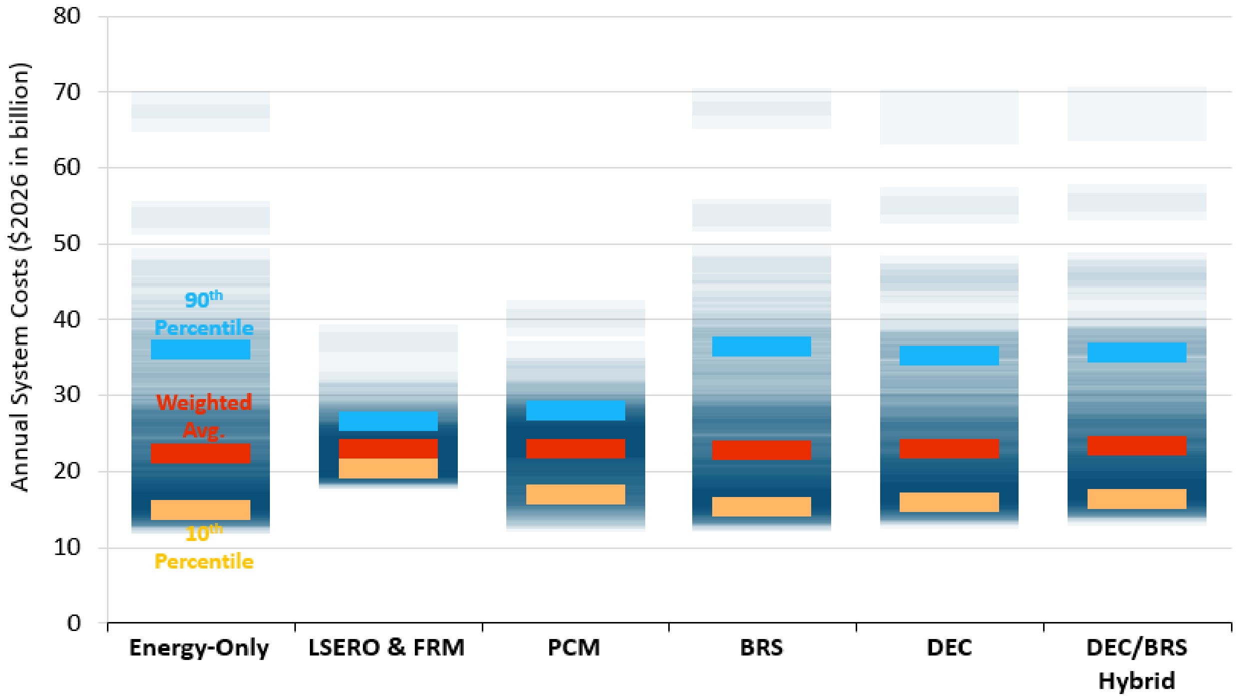
[39] Voluntary hedging by LSEs can mitigate exposure to volatility.

Figure 29. Annual System Cost Variability Across Market Designs [1]



Notes:

1. Voluntary hedging by LSEs can mitigate exposure to volatility.

Like the Energy-Only market design, the BRS design relies on scarcity pricing as a primary mechanism to incent resource entry into the market. Likewise, the DEC mechanism relies on scarcity pricing to compensate and incentivize all non-DEC resources in the market, ensuring that it still plays a very prominent role. Because of this, both scenarios maintain significant annual cost volatility.

On the other hand, the LSERO, FRM, and – to a smaller extent – PCM scenarios mitigate scarcity pricing by allowing the additional resources that have been procured to participate in the market. The suppression of scarcity pricing both reduces the potential for high-cost years during extreme conditions but also necessitates the development of the reliability credit product that is paid to resources even if conditions turn out to be mild. The combination of these two factors leads to both a higher floor and lower ceiling of expect annual cost outcomes. To the extent that LSEs engage in forward hedging, they can help mitigate the risk implied in this figure.

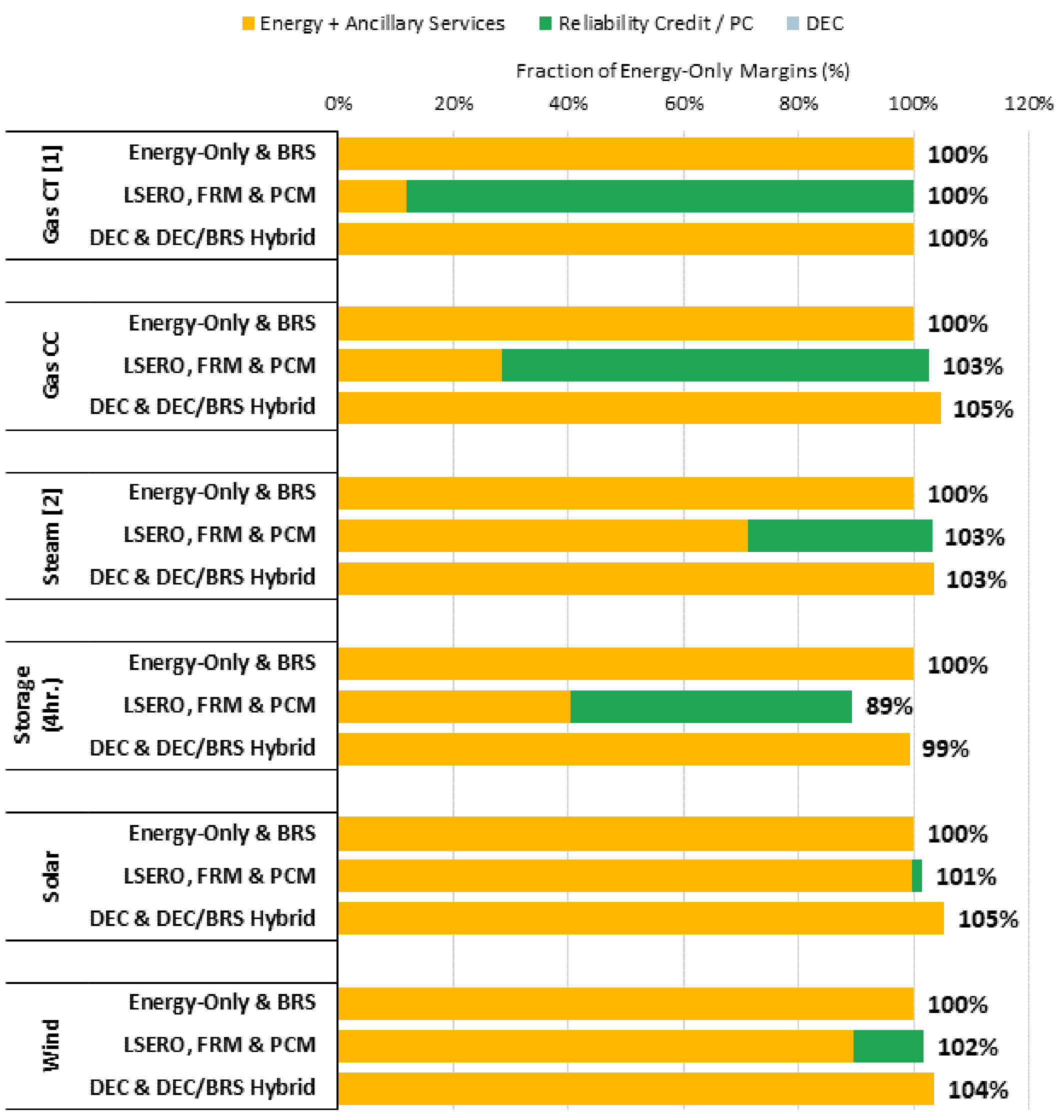
The primary difference between the LSERO/FRM and PCM designs is that the PCM design results in variability in PC price and total compensation across different realized conditions, while LSERO/FRM has the same reliability price and total compensation across all conditions because it is based on a forward expectation of conditions before they occur. However, the guarantee of 30 hours/year of PCM pricing regardless of whether the system experiences true scarcity contributes to significantly less cost volatility than a design that relies significantly on scarcity pricing.

5.2.3.3 Resource Margins

The margins that resources earn across each market design is an important indication of whether the portfolio is in equilibrium and delivering sufficient revenues to each resource to justify its entry or continued operation.

Figure 30 below provides resource margins for several resource technology classes across each market design. The key takeaway is that margins are relatively stable across each design, even though compensation breakdown between market products (energy vs. reliability credit vs. performance credit) is substantially different. This indicates that each design is in equilibrium.

Figure 30. Relative Net Margins of Resource Types Across Market Designs



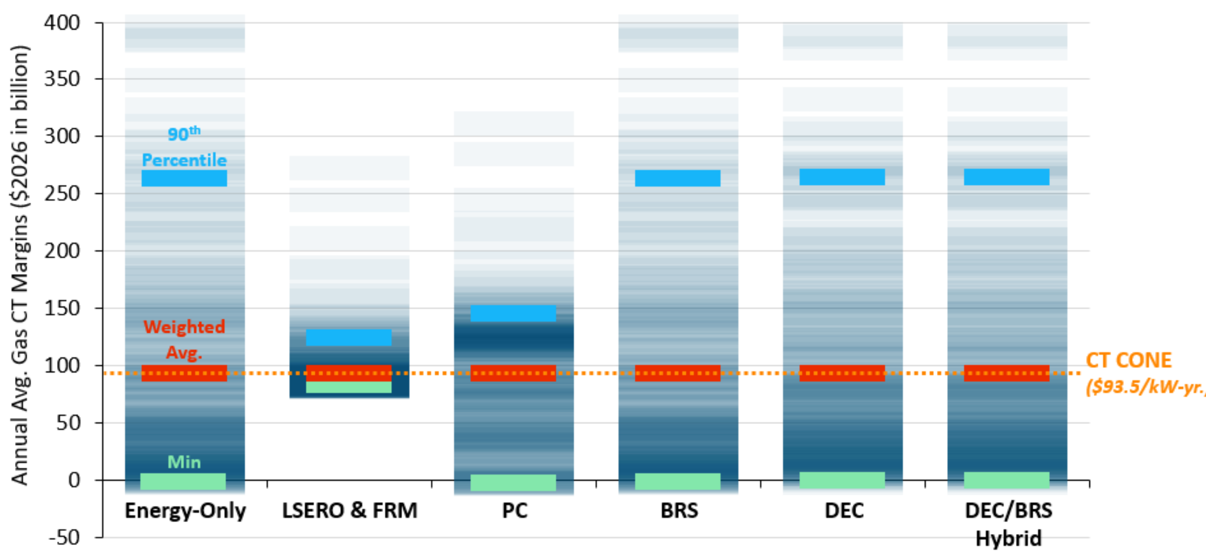
Notes:

2. "Gas CT" category in figure excludes Aero CTs, which are DEC-eligible and would therefore receive DEC payments.
3. "Steam" category includes: coal, nuclear, and natural gas steam turbine.

All market design reform proposals yield natural gas CT net margins that are equal to the gross CONE, an indication that these systems are in equilibrium. However, resource net margins can also vary significantly on a year-to-year basis, just as with total annual system costs. In the designs that rely significantly on scarcity pricing (Energy-Only, DEC, and BRS), the volatile nature of this compensation leads to volatility in CT annual net margins. In contrast, LSERO and FRM significantly decrease the volatility of CT margins through the presence of the reliability credit product as CT margin floor set equal to reliability credit price during mild years while simultaneously the incremental capacity in the market in this scenario suppresses scarcity pricing and margins during extreme years. The PCM also decreases volatility of CT margins but does not guarantee a margin floor for resources to be compensated in years where there is significant production of PCs. This is illustrated in Figure 31.

This increase stability in resource margins under the LSERO and FRM, particularly for CTs provides more certainty to investors, leading to a reduction in the cost of financing relative to the Energy-Only design, and ultimately could reduce electricity system costs beyond what is quantified in this study.

Figure 31. Gas CT Net Margins Variability Across Market Designs[40]



[40] Gas CT margins shown for BRS design reflects margins available to units that are competing in the energy and ancillary services markets – not units that are procured for BRS.

6 Sensitivity Analysis

This section examines the impact to system portfolio, reliability, and costs results if key Base Case assumptions are changed. Given the uncertainty of many future key electricity system futures, it is important to understand how each market design would perform under very different conditions. This study examines four key sensitivity factors:

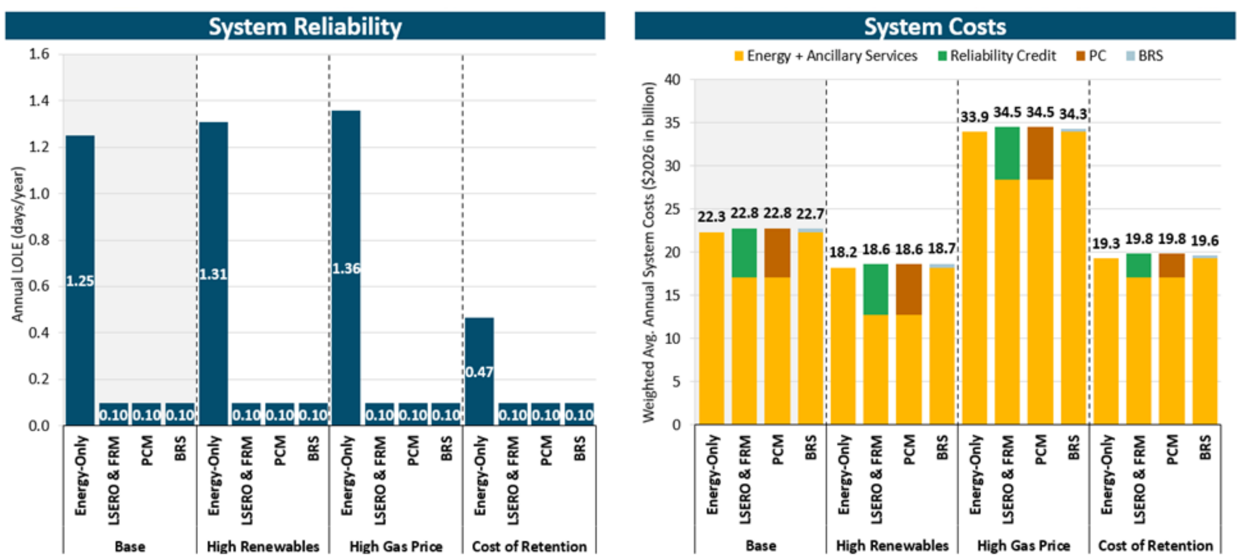
- High Renewable Penetration
- High Natural Gas Price
- No ORDC
- Equilibrium Established by "Low Cost of Retention"

This study examines the performance of Energy-Only, LSERO, FRM, PCM, and BRS market designs under these sensitivity cases. Because the DEC design under Base Case assumptions indicated both higher costs and a degradation in system reliability, it was not explored through sensitivity analysis.

For each sensitivity, the report discusses (1) how the sensitivity assumptions impact the Energy-Only design, and (2) how the market design reforms would impact that updated Energy-Only design under the sensitivity assumptions.

A summary of key sensitivity results is provided in Figure 32.

Figure 32. Summary of Quantitative Results Under Key Sensitivity Tests



6.1 High Renewables

The High Renewables sensitivity is consistent with continued rapid growth of renewable energy, battery storage, and demand-side participation. This scenario could materialize due to government policy (including the Inflation Reduction Act), continued reductions in renewable costs, increased customer preference, or other factors. While reaching this high penetration of renewable energy is unlikely by 2026, the findings of this scenario show how market designs would perform in the long term with renewable penetrations that reach the levels represented in this sensitivity.

This sensitivity increases renewables, energy storage, and demand response by the following quantities:

- **1.5x Solar and Wind:** solar increases +19,200 MW and wind increases +20,300 MW
- **2.3x Storage:** each incremental MW of solar in this sensitivity is paired with half a MW of 4-hour battery storage, increasing storage by +9,600 MW
- **2x Demand Response:** an increase in demand-side participation is achieved by doubling the ERCOT Emergency Response Service (ERS) by +925 MW

6.1.1 Energy-Only Design

An increase in renewables reduces resource margins, causing the exit of firm generation, relative to the Base Case scenario as illustrated in Table 28 below.

Table 28. Impact of High Renewables Sensitivity on Energy-Only Design Equilibrium Portfolio

	Total Installed Summer Capacity (MW) [1]		
Resource Type	Base Case	High Renewables	Change
Nuclear	4,973	4,973	–
Coal	7,396	–	-7,396
Gas	43,283	37,359	-5,924
Hydro [2]	372	372	–
Biomass	163	163	–
Wind	40,605	60,907	+20,302
Solar	39,347	58,537	+19,190
Batteries	7,411	17,011	+9,600
Other [3]	12,134	13,345	+1,212

Notes:

1. Values shown in table are exact model outputs; however, for ease of reading, significant figures have been used when referring to these values throughout the body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
3. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

The additional renewable capacity provides incremental capability to the system (increasing reliability), but also reduces resources margins, causing the exit of firm generation (decreasing reliability) under equilibrium conditions. The net effect of these two factors relatively offset each other, with a slight degradation in system reliability resulting in a similar level of reliability under equilibrium conditions (an LOLE of 1.31 days per year).

Because renewables generally bid into the energy market at $0 (or lower to capture the federal production tax credit or Texas renewable energy credits), further deployment of these types of resources will reduce wholesale energy prices. This effect is illustrated in Table 29, which shows a roughly 20% decrease in system costs across all market designs.

6.1.2 *Alternative Market Designs*

The High Renewables sensitivity is tested upon the LSERO, FRM, PCM, and BRS designs. All designs include mechanisms intended to ensure that the system achieves a specified target reliability standard, which requires an additional 6,688 MW of natural gas CT capacity relative to the Energy-Only High Renewables sensitivity. Table 29 summarizes the cost impacts of each of the designs tested in the High Renewables sensitivity. While total costs in this sensitivity are lower than under Base Case assumptions, the relative system costs between the different market designs are similar: the LSERO, FRM, PCM, and BRS mechanisms increase costs relative to the Energy-Only High Renewables sensitivity by approximately $400 million per year.

Table 29. High Renewable Sensitivity Cost Impacts

	High Renewables Sensitivity Costs ($B/yr)			
	Energy-Only	LSERO & FRM	PCM	BRS
Energy & Ancillary Services	$18.24	$12.77	$12.77	$18.24
Reliability Credits	–	$5.84	–	–
Performance Credits	–	–	$5.84	–
Backstop Service	–	–	–	$0.42
Total System Cost	**$18.24**	**$18.61**	**$18.61**	**$18.66**
Incremental Reform Cost	–	**+$0.37**	**+$0.37**	**+$0.42**

6.2 High Gas Price

The High Gas Price sensitivity is consistent with continued high natural gas prices that could persist due to continued global instability or policies in the U.S. that restrict the supply of fossil fuels. This sensitivity assumes natural gas prices that are twice as high in 2026 as current markets predict, increasing the price of natural gas from $4.80/MMBtu to $9.60/MMBtu.

6.2.1 *Energy-Only Design*

The increase in gas prices does not have a significant impact on the market equilibrium portfolio for the Energy Only case; while minor adjustments to installed capacity for coal and natural gas are made to achieve equilibrium (see Table 29), the overall composition of the portfolio is largely unaffected[41]; the

[41] Note that this study does not attempt to account for any additional investments in renewables and storage that may be induced by high natural gas prices, instead hold the level of renewables constant based on additions from the CDR report. Over the long run, high gas prices would likely incent further investments in renewables and storage resources due to the corresponding increase in value.

impact on reliability is similarly minor, as the LOLE at market equilibrium increases from 1.3 to 1.4 days per year.

Table 30. Impact of High Gas Price Sensitivity on Energy-Only Design Equilibrium Portfolio

	Total Installed Summer Capacity (MW) [1]		
Resource Type	**Base Case**	**High Gas Price**	**Change**
Nuclear	4,973	4,973	–
Coal	7,396	7,973	+577
Gas	43,283	42,824	-459
Hydro [2]	372	372	–
Biomass	163	163	–
Wind	40,605	40,605	–
Solar	39,347	39,347	–
Batteries	7,411	7,411	–
Other [3]	12,134	12,134	–

Notes:

1. Values shown in table are exact model outputs; however, for ease of reading, significant figures have been used when referring to these values throughout the body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
3. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

While the impacts of the High Gas Price sensitivity on the portfolio are limited, the impacts on system cost are large. A higher natural gas price increases the operating cost for gas generators, whose costs frequently set the marginal energy price during non-scarcity hours. The corresponding increase in the energy price translates to a significant increase in costs, which increase by approximately 50%.

6.2.2 Alternative Market Designs

Because each of the market design tested in this sensitivity (LSERO, FRM, PCM, and BRS) are designed to achieve a specified standard for reliability, the reliability outcome is unchanged from the Base Case assumptions: all reforms achieve an LOLE of 0.1 days per year in market equilibrium, an improvement relative to the Energy Only High Gas sensitivity (1.4 days per year).

Despite the increase in total cost due to higher gas prices, the relative cost increases of each market design are similar to the Base Case assumptions, with the LSERO, FRM, PCM, and BRS High Gas sensitivities each resulting in costs that are between $400-500 million above the costing more than the Energy-Only High Gas sensitivity. The fact that the cost increases associated with each of the reforms is not sensitive to the price of natural gas reflects the fact that the improvements in system reliability require additional gas generation infrastructure but do not expose consumers to significant additional gas price risk beyond what would be expected under an energy-only design. These results are illustrated in Table 31 below.

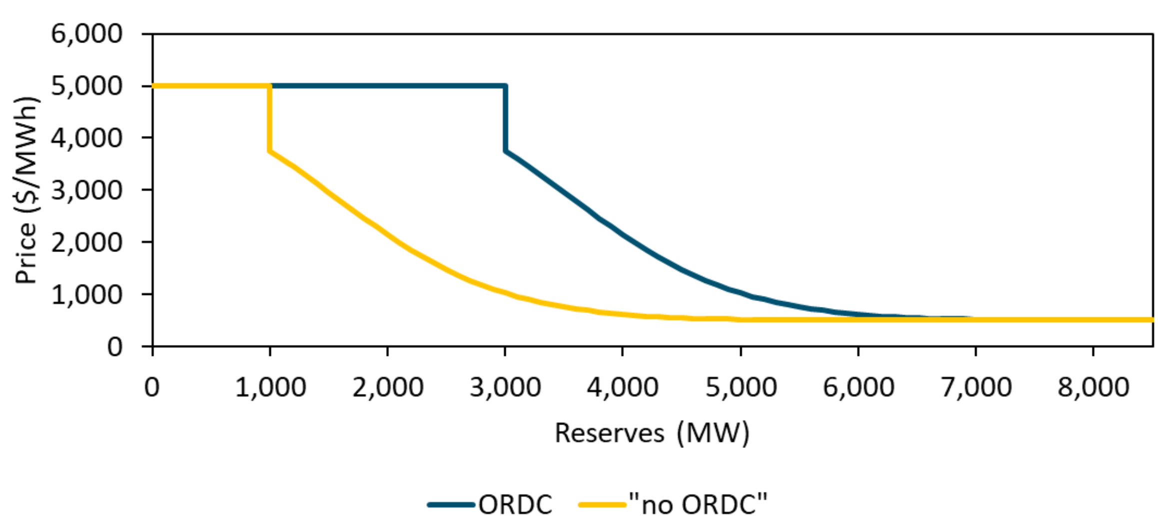
Table 31. High Gas Price Sensitivity System Costs

	High Gas Price Sensitivity Costs ($B/yr)			
	Energy-Only	LSERO & FRM	PCM	BRS
Energy & Ancillary Services	$33.93	$28.42	$28.42	$33.93
Reliability Credits	–	$6.04	–	–
Performance Credits	–	–	$6.04	–
Backstop Service	–	–	–	$0.38
Total System Cost	**$33.76**	**$34.37**	**$34.47**	**$34.31**
Incremental Reform Cost	–	**+$0.53**	**+$0.53**	**+$0.38**

6.3 No ORDC

The Energy-Only market design relies significantly on scarcity pricing, largely formed through the administrative ORDC construct, to provide the economic signals for resource entry and retention. In the LSERO and FRM market design, the increase in dispatchable capacity significantly reduces the presence of scarcity pricing. This naturally leads to the questions of whether the ORDC mechanism is needed under an LSERO or FRM market design and how its elimination would impact system portfolio, reliability, and cost. To address this question, this sensitivity examines the impact of "No ORDC" sensitivity, represented through the curves in Figure 33. The "No ORDC" curve is meant to represent only natural scarcity pricing that would result in the market without any administrative increases.

Figure 33. ORDC and "NO ORDC" Sensitivity Price Curves



6.3.1 Energy-Only Design

The elimination of the ORDC in the Energy-Only market design results in a significant reduction in resource margins, leading to the exit of a significant quantity of natural gas CT capacity as illustrated in Table 32 below.

Table 32. Impact of No ORDC Sensitivity on Energy-Only Design Equilibrium Portfolio

	Total Installed Summer Capacity (MW) [1]		
Resource Type	**Base Case**	**No ORDC**	**Change**
Nuclear	4,973	4,973	–
Coal	7,396	6,395	-1,001
Gas	43,283	41,996	-1,287
Hydro [2]	372	372	–
Biomass	163	163	–
Wind	40,605	40,605	–
Solar	39,347	39,347	–
Batteries	7,411	7,411	–
Other [3]	12,134	12,134	–

Notes:

1. Values shown in table are exact model outputs; however, for ease of reading, significant figures have been used when referring to these values throughout the body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
3. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

Without the scarcity pricing signals created by the ORDC, margins to all resources are reduced. This leads to a corresponding reduction of CT capacity under equilibrium conditions and a lower level of reliability, increasing loss of load expectation from 1.3 days per year to 2.3 days per year. However, this reduction in reliability increases "true" scarcity events/pricing and correspondingly increases system costs to similar levels as the Base Case.

6.3.2 Alternative Market Designs

The elimination of the ORDC under the LSERO, FRM, and PCM designs has the potential to slightly reduce costs due to the ability of reliability credits and performance credits to compensate resources more efficiently for their contribution to system reliability relative to the ORDC construct. This is because these designs can more directly compensate resources for their availability during the hours of highest reliability risk, without compensating them during "semi-tight" hours as the existing ORDC construct does.

Removing the ORDC from the LSERO, FRM, and PCM market designs reduces system costs by $417M/year while meeting the 0.1 days/year LOLE reliability standard. These cost savings can be attributed to a reduction in ORDC payments in hours where the economic scarcity created by the ORDC is artificial since there is no physical scarcity in the system. The modeling demonstrated that in many hours – more than 10% of hours for some model iterations – the ORDC is in effect even if there is a significant headroom of uncommitted but available resources in the system, primarily gas CTs. This artificially increases energy and ancillary service costs and is an inefficiency of the ORDC construct.

Table 33. No ORDC Sensitivity System Costs

	No ORDC Sensitivity Costs ($B/yr)			
	Energy-Only	LSERO & FRM	PCM	BRS
Energy & Ancillary Services	$22.32	$16.08	$16.08	$22.32
Reliability Credits	–	$6.19	–	–
Performance Credits	–	–	$6.19	–
Backstop Service	–	–	–	$0.44
Total System Cost	**$22.32**	**$22.27**	**$22.27**	**$22.76**
Incremental Reform Cost	–	**-$0.05**	**-$0.05**	**+$0.44**

6.4 Low Cost of Retention Equilibrium

The Base Case equilibrium condition requires that each market design provide sufficient revenues to a natural gas CT to match its gross cost of new entry (CONE), which is necessary to ensure that these resources recover their full costs. This assumption holds true in the long-run or in the short-run if the system needs to attract new investment. However, if the system has a short-run surplus of capacity, resources may not need to recover their full gross CONE in order to stay in the market without retiring. Rather, these resources may only need to recover their go-forward cost of operation, which is equivalent to the unit's "cost of retention." These costs include maintenance, insurance, and staffing costs traditionally referred to as fixed operations and maintenance. This study shows that the "pre-equilibrium" 2026 system has a surplus of resources that need to be retained to achieve target reliability as opposed to incenting new dispatchable resources into the system.

This sensitivity analyzes an alternative condition for market equilibrium, where resources only need to cover a go-forward "Low Cost of Retention" of $50/kW-yr instead of "cost of new entry" of $93.5/kW-yr. From a resource retention perspective, natural gas CTs have relatively low go-forward cost of operation and other resource types such as coal have higher go-forward costs. The U.S. EIA estimates that coal fixed operations and maintenance costs range from $40-$55/kW-yr, and this study assumes a value of $50/kW-yr as low cost of retention requirement.[42]

6.4.1 Energy-Only Design

Performance of market designs under a "Low Cost of Retention" equilibrium reduces resource margin requirements and does not result in the same level of resource exit as in the Energy-Only Base Case. Table 34 illustrates the Energy-Only system portfolio under this sensitivity and compares it to that of the Base Case.

[42] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

Table 34. Impact of Low Cost of Retention Sensitivity on Energy-Only Design Equilibrium Portfolio

Resource Type	Total Installed Summer Capacity (MW) [1] Base Case	Low Cost of Retention	Change
Nuclear	4,973	4,973	–
Coal	7,396	7,396	–
Gas	43,283	45,355	+2,072
Hydro [2]	372	372	–
Biomass	163	163	–
Wind	40,605	40,605	–
Solar	39,347	39,347	–
Batteries	7,411	7,411	–
Other [3]	12,134	12,134	–

Notes:

1. Values shown in table are exact model outputs; however, for ease of reading, significant figures have been used when referring to these values throughout the body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.
3. "Other" category includes: reserve shed (2,000 MW), emergency gen (470 MW), emergency response service (925 MW), power balance penalty curve (200 MW), load resources (1,591 MW), T&D service providers (287 MW), private use networks (4,262 MW), 4 coincident peak (900 MW), and price responsive demand (1,500 MW).

Under the Energy-Only design, the Low Cost of Retention sensitivity results in the retention of more natural gas capacity (less equilibrium retirements), ultimately leading to a higher level of reliability than in the Energy-Only Base Case: the LOLE in equilibrium decreases from 1.25 to 0.47 days per year. Across all design options, total system costs are also reduced under the Low Cost of Retention sensitivity, as the presence of more capacity in the system reduces the frequency of scarcity pricing. System costs under the Low Cost of Retention sensitivity are $19.1 billion/yr, 14% lower than under Base Case assumptions.

6.4.2 Alternative Market Designs

Because the LSERO, FRM, PCM, and BRS scenarios target 0.1 LOLE, these mechanisms do not need to procure as many resources for reliability since the Energy-Only market is procuring more capacity on its own. This, combined with a reduction in the price of reliability credits (because resources will no longer require a reliability price to cover their full gross CONE but rather only enough to cover their retention costs), reduces the total cost of the alternative market designs in this sensitivity. However, because Energy-Only scenario costs are also lower, the incremental cost of alternative market designs is similar to the Base Case and other sensitivity results. Cost results are summarized in Table 35 below.

Table 35. Low Cost of Retention Sensitivity System Costs

	Low Cost of Retention Sensitivity Costs ($B/yr)			
	Energy-Only	LSERO & FRM	PCM	BRS
Energy & Ancillary Services	$19.10	$17.12	$17.12	$19.10
Reliability Credits	–	$2.68	–	–
Performance Credits	–	–	$2.68	–
Backstop Service	–	–	–	$0.29
Total System Cost	**$19.10**	**$19.80**	**$19.80**	**$19.60**
Incremental Reform Cost	–	**+$0.49**	**+$0.49**	**+$0.29**

6.5 LSERO, FRM, and PCM Technology Eligibility

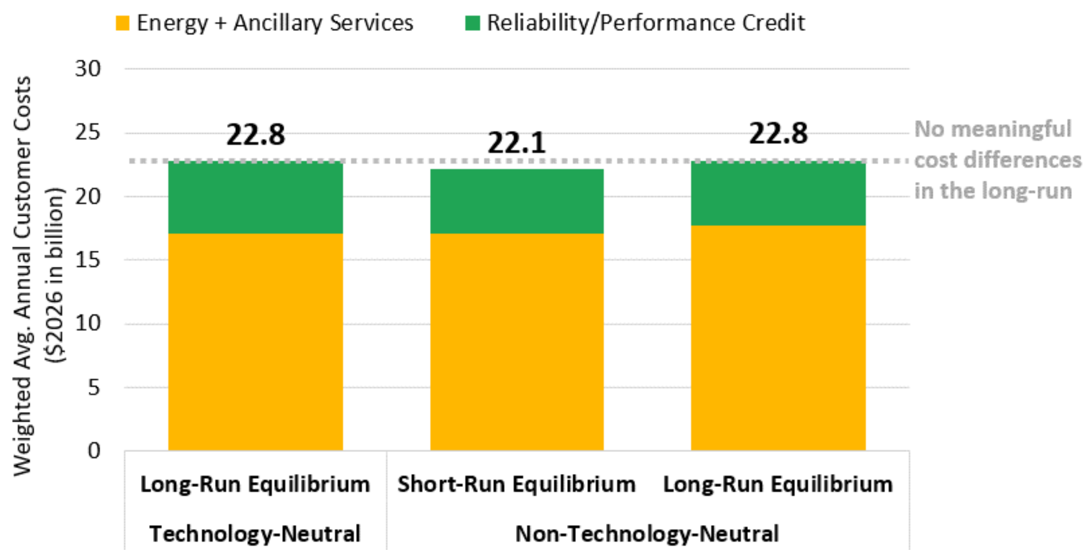
The study assumes that, for the LSERO, FRM, and PCM market designs, all resources are evaluated on a "technology-neutral" basis based on their ability to contribute to system reliability needs. Under such a technology-neutral framework, resources are evaluated based solely on their capability to generate during the hours of highest reliability risk. An alternative implementation of these designs could create eligibility criteria based on technology specifications that might exclude certain technologies from participation. One such implementation of interest to a subset of PUCT Commissioners would exclude the participation of wind and solar resources. In the short-run, implementing such a policy would decrease system costs by the quantity of reliability credit payments that would have gone to wind and solar resources. However, in the long-run, this reduction in compensation could result in smaller wind and solar buildout (relative to the counterfactual), which would have the effect of increasing energy prices. It is important to note that renewable penetrations are still relatively high in all cases due to the presence of federal subsidies such as the Inflation Reduction Act. This study analyzes three different implementation options of the LSERO, FRM, and PCM designs as listed below:

- **Technology-neutral in long-run equilibrium**
- **Non-technology-neutral (exclude wind/solar) in short-run equilibrium**
- **Non-technology-neutral (exclude wind/solar) in long-run equilibrium**

The technology-neutral long-run equilibrium scenario is identical to what is shown in the Base Case. The non-technology-neutral short-run equilibrium removes reliability credit compensation to wind and solar and makes no other changes. Wind margins would decrease from $126.3/kW-yr in the Energy-Only design to $113.0/kW-yr in the non-technology-neutral LSERO and FRM.

In the long run, this analysis shows that the lower overall wind compensation could cause a reduction of approximately 4,400 MW of wind capacity in equilibrium, which increases LOLE above the 0.1 days/yr reliability standard. More gas CT capacity would need to enter the system to ensure the system achieves 0.1 days/yr LOLE standard due to the lower wind capacity. The lower wind capacity increases energy costs (an identical but opposite impact that high renewables have in decreasing energy costs). The combined impact of higher reliability credit payments to natural gas (due to more natural gas capacity) and higher energy costs (due to lower wind penetrations) offsets the reduction in cost savings from the reduction in reliability credit payments to wind and solar.

Figure 34. Non-Technology-Neutral LSERO, FRM, and PCM Long-Run Cost Comparison



7 Qualitative Review

In addition to the differences in market outcomes analyzed quantitatively above, there are a number of qualitative factors that distinguish the designs. This section presents E3's qualitative assessment of each market design reform proposal in a number of categories. E3 used a simple "stoplight" scoring process where red indicates concern, green indicates no concern, and yellow is neutral. The categories are based on potential areas of concern indicated in stakeholder and PUCT comments. These scoring assessments represent E3's independent view based on experience working with market participants across a number of jurisdictions and market designs in North America. These assessments are unavoidably subjective and E3 understands and expects that stakeholder evaluations may be different and that stakeholders may have additional areas of concern that are not evaluated here. A summary of qualitative findings is presented in the table below with more detail provided throughout the rest of this section.

Table 36: Summary of Qualitative Performance of Each Market Design

	LSERO	FRM	PCM	BRS	DEC
Market Power Risk	Moderate Market Power Risk	Low Market Power Risk	Low Market Power Risk	Low Market Power Risk	Low Market Power Risk
Market Competition & Efficiency	Most Competitive	Most Competitive	Neutral	Least Competitive	Least Competitive
Implementation Timeline	Long Implementation Timeline	Long Implementation Timeline	Long Implementation Timeline	Short Implementation Timeline	Moderate Implementation Timeline
Administrative Complexity	High Complexity	High Complexity	High Complexity	Low Complexity	Moderate Complexity
Performance Incentives and Penalties	Strong Performance Incentives	Strong Performance Incentives	Strong Performance Incentives	Moderate Performance Incentives	Weak Performance Incentives
Ability to Address Extreme Weather Events	Most Potential to Address Extreme Weather	Most Potential to Address Extreme Weather	Moderate Potential to Address Extreme Weather	Moderate Potential to Address Extreme Weather	Least Potential to Address Extreme Weather
Cost and Revenue Stability	More stable costs and revenues	More stable costs and revenues	Moderately stable costs and revenues	Less stable costs and revenues	Less stable costs and revenues

Load Migration	Moderate ability to address load migration	Strong ability to address load migration	Strong ability to address load migration	Strong ability to address load migration	Strong ability to address load migration
Demand Response	Strong signals for demand response	Strong signals for demand response	Strong signals for demand response	Strong signals for demand response	Strong signals for demand response
Prior Precedent	Significant precedent	Significant precedent	No prior precedent	Moderate precedent	No prior precedent

7.1 Market Power Risk

Market power can be exerted by pivotal market sellers (or buyers) who can economically or physically withhold supply and increase prices above (or below) competitive levels and influence market outcomes. A pivotal supplier is defined as a supplier who is large enough such that their behavior in the market can affect market price. In an efficient, competitive market, no single participant is large enough to affect market price. However, the electricity market often does have market participants that are large enough in certain circumstances to exert market power. This section evaluates the potential for market participants to exert market power and the feasibilities of potential remedies.

Table 37. Assessment of Market Power Risk under Each Design

Load Serving Entity Reliability Obligation (LSERO)	
Moderate Market Power Risk	In the LSERO design, demand for reliability credits is generally very close to supply, creating the potential for pivotal suppliers. The presence of pivotal suppliers in the reliability credit market is generally more common than in the energy market (where supply significantly exceeds demand in most hours). Entities that are "net long" on generation may have an incentive to economically withhold capacity in order to increase prices. Market participants that are both generators and retailers (i.e., "gen-tailers") that have more retail load than generation would not have an incentive to withhold since they are net buyers from the market and would not benefit from higher prices. The independent market monitor (IMM) may be able to address market power concerns in the LSERO design through analysis of market concentration and monitoring of transactions through a public bulletin board process. However, without a centralized market clearing structure, tools such as sloped demand curve and bid mitigation are not available to the IMM.
Forward Reliability Market (FRM)	
Low Market Power Risk	In the FRM design, demand for reliability credits is generally very close to supply, creating the potential for pivotal suppliers. The presence of pivotal suppliers in the reliability credit market is generally more common than in the energy market (where supply significantly exceeds demand in most hours). Entities that are "net long" on generation may have an incentive to economically withhold capacity in order to increase prices.

	Market participants that are both generators and retailers (i.e., "gen-tailers") that have more retail load than generation would not have an incentive to withhold since they are net buyers from the market and would not benefit from higher prices. The IMM can address potential market power concerns and currently does so effectively for reliability products in other jurisdictions (e.g., PJM, ISONE, NYISO). Market power in a centralized auction process can be addressed explicitly using tools such as a sloped demand curve and bid mitigation.
Performance Credit Mechanism (PCM)	
Low Market Power Risk	In the PCM, demand for performance credits during the hours of highest reliability risk (e.g., 30 hours) will generally be very close to the supply of performance credits. The potential for withholding in these hours is likely similar to the potential for withholding in the energy or ancillary service market during hours of energy scarcity. The IMM can address potential market power concerns and currently does so effectively for the ERCOT energy market. Additionally, the feature of a sloped demand curve limits the ability of participants to increase price by withholding supply).
Backstop Reliability Service (BRS)	
Low Market Power Risk	The competitive procurement of BRS resources would be conducted by ERCOT on a forward basis for a relatively small subset of generators (~5,000 MW depending on the scenario). Both the forward contracting dimension and the competitive procurement will likely not lead to any pivotal suppliers that can exert market power. However, it will be important for the IMM to monitor a potential BRS market to ensure that prices are competitive.
Dispatchable Energy Credits (DEC)	
Low Market Power Risk	Market power has not proven to be a significant issue in the renewable energy credit (REC) market in ERCOT or other markets across the U.S. Although a dispatchable energy credit (DEC) market is yet untested in the U.S., it is reasonable to think that it would perform similarly to the REC market due to its similar construct and features. A potential key difference between REC and DEC markets would be the size of supply. REC markets are extremely large with broad eligibility for many resources. To the extent that DEC markets are more narrowly defined with fewer eligible resources, this would increase the risk that a seller could exert market power. A key potential remedy to market power in this market would be the introduction of a "banking" and "borrowing" system that allows DEC buyers to under procure in one year and make up for that shortfall in future years. In any case, it will be important for the IMM to monitor a potential DEC market to ensure that prices are competitive.

7.2 Market Competition & Efficiency

The ERCOT market is one of the most robust competitive electricity markets in the U.S. A large number of generators are owned and operated by non-regulated entities, and many consumers are served by non-regulated retailers. Maintaining the market's competitive feature is an important aspect of any design. This section evaluates each market design reform proposal along three primary dimensions of competition:

1. The extent to which the new market product is subject to competition;
2. The extent to which the reform interferes with or distorts competition within the energy and ancillary services markets;
3. The extent to which LSEs can procure their own supply or hedge their costs of procuring the required product.

Table 38. Assessment of Market Competition and Efficiency of Each Design

Load Serving Entity Reliability Obligation (LSERO)	
Most Competitive	1. The LSERO design values the reliability contribution of all resources in a technology-neutral manner based on their ability to contribute to system reliability. [43] 2. All resources, whether they are participants in the reliability credit market or not, are eligible to fully participate in the energy/AS market which enables these resources to help moderate energy prices. 3. LSEs can almost completely hedge their risk by procuring reliability credits through bilateral forward contracts.
Forward Reliability Market (FRM)	
Most Competitive	1. The FRM design values the reliability contribution of all resources in a technology-neutral manner based on their ability to contribute to system reliability.[44] 2. All resources, whether they are participants in the reliability credit market or not, are eligible to fully participate in the energy/AS market which enables these resources to help moderate energy prices. 3. LSEs can procure reliability credits in the ERCOT auction or can almost completely hedge their risk through bilateral forward contracts.
Performance Credit Mechanism (PCM)	
Neutral	1. While the PCM design compensates all resources in a technology-neutral manner based on their demonstrated ability to contribute to system needs during the tightest 30 hours[45] each year, this may not be completely aligned with the hours that drive system reliability requirements. [46] For example, a resource's true

[43] If the LSERO design were to be implemented in a non-technology-neutral manner, e.g., by excluding the cost/compensation of resources such as wind or solar, this would diminish its effectiveness as a competitive market mechanism.

[44] If the FRM design were to be implemented in a non-technology-neutral manner, e.g., by excluding the cost/compensation of resources such as wind or solar, this would diminish its effectiveness as a competitive market mechanism

[45] Or another administratively pre-determined number of hours

[46] If the PCM design were to be implemented in a non-technology-neutral manner, e.g., by excluding the cost/compensation of resources such as wind or solar, this would diminish its effectiveness as a competitive market mechanism

	reliability value may be driven by its performance during extreme events that do not occur every year (which could be captured through an accreditation process), while the PCM would compensate resources for their performance each year, even if extreme events did not occur. 2. All resources, whether they are participants in the performance credit market or not, are eligible to fully participate in the energy/AS market which enables these resources to help moderate energy prices. It is possible that some resources may change their bidding behavior to increase their availability during the 30 hours (for example: a battery increasing its bid price to avoid discharge and increasing its ability to offer in more hours). 3. LSEs can procure PCs in the ERCOT settlement process or can almost completely hedge their risk through the voluntary forward market.
Backstop Reliability Service (BRS)	
Least Competitive	1. BRS eligibility is determined administratively and restricted to a subset of resources in a manner that is not entirely consistent with their contributions to reliability. For example, an 8-hour duration requirement means that a 7-hour duration resource would not be eligible to participate, even though its value for system reliability is clearly not zero and may not be much different than an 8-hour resource. If ERCOT is able to independently set requirements and procure resources based on their expected contribution to reliability, the market competitiveness would be higher. 2. Because BRS resources are held out of the market, they are not available to be utilized, even if they would be lower cost than the resources that dispatch ahead of them. This distorts and increases energy dispatch costs. Additionally, the dispatch of BRS resources at the price cap creates scarcity pricing in hours where no physical scarcity may actually exist. 3. Because the costs associated with the BRS are procured directly by ERCOT, LSEs do not have an ability to procure their own resources.
Dispatchable Energy Credits (DEC)	
Least Competitive	1. DEC eligibility is determined administratively and restricted to a subset of resources in a manner that is not entirely consistent with their contributions to reliability. For example, a generator with an 8,999 Btu/kWh heat rate is eligible to generate DECs, while a generator with a 9,001 Btu/kWh heat rate is not even though both resources contribute identically to system reliability. If ERCOT is able to independently set requirements and procure resources based on their expected contribution to reliability, the market competitiveness would be higher. 2. In addition, a resource is eligible to generate DECs and earn the associated revenues if it clears in the energy or ancillary service market. This creates the incentive for DEC generators to reduce their bids below short-run marginal cost by an amount equal to what they would expect to earn in the DEC market. The reduction in bids below short-run marginal cost is a distortion to the energy market and could result in DEC-eligible generators dispatching in place of resources that have actual lower short-run marginal energy costs.

7.3 Implementation Timeline

Rapid implementation of any new reliability mechanism is important for improving system reliability in the near-term. There are two important factors that impact implementation time for each proposed market design

1. How long would it take to develop full program rules and regulations?
2. How long would it take the market to develop the resources required to satisfy the new market design requirements?

This section evaluates the time to implementation for each market design reform proposal. In the event that multiple designs were implemented in a hybrid or sequential fashion, this could extend the total implementation timeline due to ERCOT personnel limitations.

Table 39. Assessment of Each Design's Implementation Timeline

Load Serving Entity Reliability Obligation (LSERO)	
Long Implementation Timeline	The LSERO design is nearly as complex as the FRM and requires significant technical analysis and stakeholder engagement to develop final rules. Other markets with a reliability mechanism have tariff rules that have been developed and modified over many years, ensuring that these markets perform as intended. The primary analytical tasks to fully stand up an LSERO are 1) develop a structure for resource accreditation, 2) determine system and LSE needs and 3) develop methodology to certify reliability credit ownership stemming from bilateral trading. Each of these issues is discuss in more detail in Section *8, Additional Considerations and Implementation Options*. It would likely take two years to develop the rules and regulations for the LSERO. Once the rules and regulations are developed, the market will need time to respond to the market signals created by this new product. To the extent that new resources would need to be developed, this would require time, likely 1-2 years. However, to the extent that the LSERO would prevent existing resources from retiring, than this would not require significant if any time. E3 therefore estimates that 2-4 years would be needed to fully implement the LSERO.
Forward Reliability Market (FRM)	
Long Implementation Timeline	The FRM design is the most complex and requires the most technical analysis and stakeholder engagement to develop final rules. Other markets with a reliability mechanism have tariff rules that have been developed and modified over many years, ensuring that these markets perform as intended. The primary analytical tasks to fully stand up an FRM are 1) develop a structure for resource accreditation, 2) determine system needs, and 3) develop rules for market clearing and transparency. Each of these issues is discussed in more detail in Section *8, Additional Considerations and Implementation Options*. It would likely take two years to develop the rules and regulations for the FRM.

	Once the rules and regulations are developed, the market will need time to respond to the market signals created by this new product. To the extent that new resources would need to be developed, this would require time, likely 1-2 years. However, to the extent that the FRM would prevent existing resources from retiring, than this would not require significant if any time. E3 therefore estimates that 2-4 years would be needed to fully implement the FRM.
Performance Credit Mechanism (PCM)	
Long Implementation Timeline	The PCM design is complex and requires significant technical analysis and stakeholder engagement to develop final rules. Other markets with a reliability mechanism have tariff rules that have been developed and modified over many years, ensuring that these markets perform as intended. A completely new set of tariff rules would need to be developed since a PCM has not previously been implemented in any other market. The primary analytical tasks to fully stand up a PCM would be 1) determine system PC needs 2) develop rules to conclude when the most critical hours occur and 3) develop rules for market clearing and transparency. Each of these issues is discussed in more detail in Section *8, Additional Considerations and Implementation Options*. It would likely take two years to develop the rules and regulations for the PCM. Once the rules and regulations are developed, the market will need time to respond to the market signals created by this new product. To the extent that new resources would need to be developed, this would require time, likely 1-2 years. However, to the extent that the PCM would prevent existing resources from retiring, than this would not require significant if any time. E3 therefore estimates that it would take approximately 2-4 years to fully implement the PCM.
Backstop Reliability Service (BRS)	
Short Implementation Timeline	E3 views the BRS as the quickest design to implement, assuming ERCOT were to pursue a pay-as-bid mechanism (options described in Section *8, Additional Considerations and Implementation Options*) and could likely be developed in 1 year. As with other designs, the market will need time to respond to the market signals created by this new product, requiring 1-2 years for new development or minimal time for retention of existing resources. In aggregate, E3 estimates that the BRS would take approximately 1-3 years to fully implement.
Dispatchable Energy Credits (DEC)	
Moderate Implementation Timeline	The DEC market design is somewhat complex, with the primary challenges being to 1) define total DEC targets 2) define resource eligibility 3) develop rules for how a resource can generate a DEC (such as which markets it must clear in and what hours of day). E3 expects it would take approximately 1-2 year to develop all rules and regulations for a DEC market. As with other designs, the market will need time to respond to the market signals created by this new product, requiring 1-2 years for new development or minimal time for retention of existing resources. In aggregate, E3 estimates that the DEC would take approximately 1-4 years to fully implement.

7.4 Administrative Complexity

The administrative complexity of each market design reform proposal represents the number of steps required to implement each design, the ability of PUCT and ERCOT staff to implement the new design, and the ability of stakeholders to understand the new process in a clear and transparent manner. This section evaluates the administrative complexity for each market design reform proposal.

Table 40. Assessment of Each Design's Administrative Complexity

Load Serving Entity Reliability Obligation (LSERO)	
High Complexity	Implementing an LSERO requires a number of analytically complex tasks, each of which should be conducted in a public and transparent manner. The following provides a list of tasks that must be executed by ERCOT or the PUCT to implement an LSERO: • Determine target reliability standard • Determine total system need for reliability resources to meet target standard • Accredit individual resources based on contributions to system reliability needs • Determine method and process to allocate total system need to individual LSEs • Develop process for LSEs to show compliance with reliability requirements • Develop performance assessment protocols These steps add significant administrative complexity to the existing energy only market structure.
Forward Reliability Market (FRM)	
High Complexity	Implementing an FRM requires a number of analytically complex tasks, each of which should be conducted in a public and transparent manner. The following provides a list of tasks that must be executed by ERCOT or the PUCT to implement an FRM: • Determine target reliability standard • Determine total system need for reliability resources to meet target standard • Accredit individual resources based on contributions to system reliability needs • Develop auction process for market clearing and transparency • Determine method and process to allocate costs to individual LSEs • Develop performance assessment protocols These steps add significant administrative complexity to the existing energy only market structure.
Performance Credit Mechanism (PCM)	
High Complexity	Implementing a PCM requires a number of analytically complex tasks, each of which should be conducted in a public and transparent manner. The complexity of a PC market design is similar to the LSERO and FRM, with the exception that the PCM avoids the need for resource accreditation. These include: • Determine target reliability standard • Determine total system PC need for reliability resources to meet target standard • Develop auction process for market clearing and transparency • Determine method and process to allocate costs to individual LSEs Because the steps to determine total system need for performance credits requires the development of the same model required to perform resource accreditation, E3 does not view this as substantially less complex than the LSERO and FRM designs.

Backstop Reliability Service (BRS)	
Moderate Complexity	Implementing a BRS market design requires the execution of multiple tasks, such as: • Determine a BRS quantity requirement • Determine BRS eligibility criteria • Develop an ERCOT procurement process To the extent that ERCOT bases the BRS quantity requirement on how many resources are needed to achieve a specified reliability standard (e.g., 0.1 days/yr LOLE), this will require the development of the same type of modeling as used in the LSERO, FRM, and PC market designs. However, the overall number of steps to implement the BRS design is smaller than the LSERO, FRM, or PCM market designs. Centralized procurement processes currently exist in other markets for Firm Fuel, ERS, Black Start, and the BRS design could likely leverage the processes of these other markets to reduce new complexities.
Dispatchable Energy Credits (DEC)	
Moderate Complexity	Implementing a DEC design requires a number of administrative tasks, such as: • Determine DEC resource eligibility criteria • Determine eligible time periods for DEC generation • Determine clearing rules for DEC generation • Determine total DEC quantity requirements • Develop a process for LSEs to demonstrate compliance with DEC requirements While each of these steps should require deliberation conducted in a public and transparent manner, none of these steps requires the modeling required under an LSERO, FRM, PCM, or BRS market design.

7.5 Real-Time Performance Incentives and Penalties

An important feature of any new reliability mechanism is its ability to incentivize resources to perform during hours of highest reliability risk. This section evaluates the ability of each market design reform proposal to incent resources to perform in real-time and thus increase the likelihood that the system will achieve target reliability.

Table 41. Assessment of Each Design's Strength of Real-Time Performance Incentives and Penalties

Load Serving Entity Reliability Obligation (LSERO)	
Strong Performance Incentives	The LSERO market design financially penalizes all resources for underperformance (relative to their accredited reliability value) during the hours of highest reliability risk each year (30 hours per year). These hours are determined *ex-post*, ensuring that resources are only evaluated during hours of highest risk. Resources that overperform (relative to their accredited reliability value) can generate credits that are used to offset penalties for underperforming resources, creating an incentive for all resources to maximally perform when needed. The penalties implemented in an LSERO must be meaningful, with the potential for resources to be penalized more than they were compensated in reliability credits in cases of extreme underperformance.
Forward Reliability Market (FRM)	

Strong Performance Incentives	The FRM design financially penalizes all resources for underperformance (relative to their accredited reliability value) during the hours of highest reliability risk each year (30 hours per year). These hours are determined ex-post, ensuring that resources are only evaluated during hours of highest risk. Resources that overperform (relative to their accredited reliability value) can generate credits that are used to offset penalties for underperforming resources, creating an incentive for all resources to maximally perform when needed. The penalties implemented in an FRM must be meaningful, with the potential for resources to be penalized more than they were compensated in reliability credits in cases of extreme underperformance.
Performance Credit Mechanism (PCM)	
Strong Performance Incentives	The PCM market design financially rewards resources for performance during the hours of highest reliability risk each year (30 hours per year). These hours are determined *ex-post*, ensuring that resources are only evaluated during hours of highest risk. Resources that are not available during these hours are not awarded performance credits. Moreover, units that sold credits in the forward PC market but did not actually perform will receive a financial penalty by needing to procure PCs in the retrospective settlement process. The financial reward for performance during these hours is meaningful and is structured in such a way to ensure that resources are able to earn contribution to capital cost.
Backstop Reliability Service (BRS)	
Moderate Performance Incentives	The BRS design can be structured to financially penalize BRS resources for underperformance (relative to their cleared value) during any hour the resources are dispatched at the offer cap. This structure creates good alignment between real-time performance assessment and the reliability needs of the system. However, the BRS program only assesses real-time performance on a relatively small subset of the entire resource portfolio, which leads to overall moderate performance incentives. However, the BRS preserves scarcity pricing present in the current Energy-Only market and thus the corresponding real-time incentives to produce associated with this scarcity pricing for non-BRS resources.
Dispatchable Energy Credits (DEC)	
Weak Performance Incentives	The eligible hours for DEC generation (6 pm – 10pm each day) align loosely with hours of highest reliability risk, but the DEC construct does not distinguish between days where the system is tight and days with significant excess supply. As a result, 1) DEC eligible resources will be compensated for producing on days when the system is not constrained and 2) DEC eligible resources (and other resources) may be undercompensated during actual periods of reliability risk. Additionally, the DEC program only provides a modest incentive for performance to a relatively small subset of the entire resource portfolio, and non-DEC-eligible resources have no incremental incentive to perform (relative to the Energy-Only design). However, the DEC market design largely preserves scarcity pricing present in the current Energy-Only market and thus the corresponding real-time incentives to produce associated with this scarcity pricing for non-DEC resources.

7.6 Ability to Address Extreme Weather Events

Over multiple days in February 2021, as much as 20,000 MW of electric load went unserved due in part to outages from firm resources (natural gas, coal, nuclear) that exceeded 30,000 MW.[47] Since that event, the PUCT and others have implemented several reforms (including but not limited to firm fuel supply service and electric generation weatherization standards) to address these specific risks that this study assumes would lead to better performance of the thermal fleet during future Uri-like weather conditions. However, to the extent that these reforms have not solved all of the potential Uri-like risks, this section evaluates the ability of each market design reform proposal to address additional risks associated with extreme weather events.

Table 42. Assessment of Each Design's Ability to Address Extreme Weather Conditions

Load Serving Entity Reliability Obligation (LSERO)	
Most Potential to Address Extreme Weather	Resource accreditation in an LSERO design could be structured to capture risks related to fuel security, winterization, or other extreme winter weather risks. These topics are actively being explored in other markets, and market reforms appear likely.[48] Resources with access to firm supplies of fuel (such as firm natural gas pipeline contracts or on-site fuel storage) would receive higher reliability accreditation, creating a financial incentive to procure supplies of firm fuel. The primary challenge of incorporating such factors into accreditation is the complexity of accurately modeling these events given their relative infrequency. Similarly, assessing resource performance based on events that are not likely to occur each year is also a challenge for a construct assesses performance on an annual basis. However, these challenges are all actively being studied across the country and other markets have not indicated that they pose intractable challenges to incorporating these factors.
Forward Reliability Market (FRM)	
Most Potential to Address Extreme Weather	Resource accreditation in an FRM design could be structured to capture risks related to fuel security, winterization, or other extreme winter weather risks. These topics are actively being explored in other markets, and market reforms are likely.[49] Resources with access to firm supplies of fuel (such as firm natural gas pipeline contracts or on-site fuel storage) would receive higher reliability accreditation, creating a financial incentive to procure supplies of firm fuel. The primary challenge of incorporating such factors into accreditation is the complexity of accurately modeling these events given their relative infrequency. Similarly, assessing resource performance based on events that are not likely to occur each year is also a challenge for a construct that is designed to assess performance on an annual basis. However, these challenges are all actively being studied

[47] https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

[48] For example, see page 37 https://www.iso-ne.com/static-assets/documents/2022/06/iso-ne-2021-som-report-full-report-final.pdf.

[49] For example, see page 37 https://www.iso-ne.com/static-assets/documents/2022/06/iso-ne-2021-som-report-full-report-final.pdf.

	across the country and other markets have not indicated that they pose intractable challenges to incorporating these factors.
Performance Credit Mechanism (PCM)	
Moderate Potential to Address Extreme Weather	Unlike the FRM or LSERO market designs, the PCM market design does not accredit resources based on the full range of expected reliability risks, but rather assigns PCs based on actual performance in each year. However, extreme winter weather events are not events that are expected each year; the most extreme events occur approximately once per decade. Therefore, accrediting resources based on their actual performance each year poses the overcompensate resources during mild years, even if they are not able to reliably perform during extreme weather events.[50] .
Backstop Reliability Service (BRS)	
Moderate Potential to Address Extreme Weather	While the BRS mechanism could be configured to improve system performance during extreme weather events if BRS resources were required to have firm fuel and be capable of generating during fuel disruption events, this requirement was not included in the design developed by PUCT for this study. Even if a firm fuel requirement is imposed upon BRS resources, this requirement will have no direct impact on vulnerabilities that may exist in the rest of the generation portfolio.
Dispatchable Energy Credits (DEC)	
Least Potential to Address Extreme Weather	The DEC market design reform is not designed to target winter risks specifically, nor does it send market signals for investment in resource attributes that would specifically improve performance during extreme winter weather.

[50] For example, see "Historical Tight-Intervals Measurements" vs. "Simulated Marginal ELCC" https://www.brattle.com/wp-content/uploads/2022/06/Capacity-Resource-Accreditation-for-New-Englands-Clean-Energy-Transition-Report-2-Options-for-New-England.pdf.

7.7 Cost and Revenue Stability

The market designs evaluated here differ markedly in the variability of total market costs and the revenues resources earn. Lower inter-annual cost variability is beneficial for consumers because they are better able to plan for their energy bills. Lower inter-annual revenue variability is beneficial for resources because it reduces market risks, lowers debt-service coverage ratios, and may ultimately lead to lower cost of financing investments. Lower cost of financing would ultimately flow through to consumers by a reduction in the cost of new entry and thus lower market prices. This section evaluates the impacts of each market design on cost and revenue stability. This assessment draws heavily upon the data in Section *5.2.3.2, Cost Variability* on the volatility of resource revenue streams from year to year.

Table 43. Assessment of Each Design's Impact on Cost and Revenue Stability

Load Serving Entity Reliability Obligation (LSERO)	
More stable costs and revenues	The LSERO design significantly decreases the volatility of total costs and resource margins relative to the Energy-Only (status quo) design. It accomplishes this by reducing the frequency of scarcity pricing events and converting an uncertain scarcity revenue stream based on energy market prices into a more certain reliability credit revenue stream that accrues to each resource regardless of whether scarcity conditions materialize in that operating year. This decrease in volatility results in more stable energy bills for consumers and reduces risk and financing costs for new resources.
Forward Reliability Market (FRM)	
More stable costs and revenues	The FRM design significantly decreases the volatility of total costs and resource margins relative to the Energy-Only (status quo) design. It accomplishes this by reducing the frequency of scarcity pricing events and converting an uncertain scarcity revenue stream based on energy market prices into a more certain reliability credit revenue stream that accrues to each resource regardless of whether scarcity conditions materialize in that operating year. This decrease in volatility results in more stable energy bills for consumers and reduces risk and financing costs for new resources.
Performance Credit Mechanism (PCM)	
Moderately stable costs and revenues	The PCM design decreases the volatility of resource margins relative to the Energy-Only (status quo) design. It accomplishes this by converting an uncertain scarcity price revenue stream into a more certain performance credit price that would accrue to each resource regardless of whether the year turns out mild or extreme. However, the reduction of volatility is smaller than in the LSERO and FRM, as resources are still subject to the uncertainty of how many PCs are produced each year. Thus, this design reduces volatility, risk, and financing costs, but not by as much as the LSERO or FRM.
Backstop Reliability Service (BRS)	
Less stable costs and revenues	The BRS design continues to rely on scarcity pricing signals as the primary compensation mechanism for all non-BRS resources in the market. Thus, this market design reform does not reduce annual volatility of energy costs or resource margins relative to the Energy-Only (status quo) design.
Dispatchable Energy Credits (DEC)	

Less stable costs and revenues	The DEC design continues to rely on scarcity pricing signals as the primary compensation mechanism for all non-DEC resources in the market, particularly natural gas CTs. Thus, this market design reform does not reduce the volatility of energy costs or resource margins relative to the Energy-Only (status quo) design.

7.8 Load Migration

Load migration refers to the ability of retail electricity consumers to migrate from one retail provider to another. An efficient and competitive retail electricity market requires that LSEs be properly allocated costs and requirements based on *actual* system usage. In the event that requirements or costs are assessed on LSEs on a forward basis, load migration may lead actual usage to differ from this forecast. In particular, a forward requirement may create an incentive for LSEs to under-forecast their loads so that they incur lower costs. This section addresses the complexities of addressing load migration to ensure that LSEs are not over or under-assigned costs due to customer load migration.

Table 44. Assessment of Each Design's Ability to Address Load Migration

Load Serving Entity Reliability Obligation (LSERO)	
Moderate ability to address load migration	Because the LSERO market design requires LSEs to bilaterally contract for reliability credits on a forward basis, this creates a need for LSEs to forecast their usage during the hours of highest reliability risk. To the extent that an LSEs actual usage is higher or lower than forecasted due to load migration, then they should be required buy or sell reliability credits to account for the difference. While it is possible to devise a system to facilitate these transactions, it would require complex determinations of what an LSEs baseline consumption would have been. It would also likely require LSEs with excess reliability credits to transfer these to deficient LSEs at an administratively determined price in order to prevent the exercise of market power. While these challenges are addressable, they are likely complex.
Forward Reliability Market (FRM)	
Strong ability to address load migration	Because the FRM market design allocates the cost of centrally procured reliability credits to LSEs on an ex-post basis, there is no need to forecast any individual LSEs consumption. Thus, no load migration adjustments are required in this market design
Performance Credit Mechanism (PCM)	
Strong ability to address load migration	Because the PCM market design allocates the cost of centrally settled performance credits to LSEs on an ex-post basis, there is no need to forecast any individual LSEs consumption. Thus, no load migration adjustments are required in this market design
Backstop Reliability Service (BRS)	
Strong ability to address load migration	Because the BRS market design allocates the cost of centrally procured backstop resources to LSEs on an ex-post basis, there is no need to forecast any individual LSEs consumption. Thus, no load migration adjustments are required in this market design
Dispatchable Energy Credits (DEC)	
Strong ability to address load migration	Because the DEC market design requires LSEs to make a DEC showing at the end of the compliance period, there is no need to forecast any individual LSEs consumption. Thus, no load migration adjustments are required in this market design

7.9 Demand Response

In order for an electricity system to efficiently deliver reliability at least cost, all resources must be able to compete on equal footing, including both supply-side and demand-side resources. This section evaluates the ability of each market design reform to send appropriate market signals to demand response resources such that they can compete on a level playing field.

Table 45. Assessment of Each Design's Ability to Facilitate Demand Response

Load Serving Entity Reliability Obligation (LSERO)	
Strong ability to facilitate demand response	Under an LSERO framework, demand response can participate as either a demand-side resource (dispatching during the hours of highest reliability risk and reducing the need for an LSE to procure reliability credits) or as a supply-side resource (selling forward reliability credits to an LSE and incurring a real-time performance obligation). In either case, demand response resources are able to compete on a level playing field to provide reliability relative to other resources. Additionally, LSEs that are able to reduce or eliminate their load during the hours of highest reliability risk can reduce or eliminate any requirement to procure reliability credits.
Forward Reliability Market (FRM)	
Strong ability to facilitate demand response	Under an FRM framework, demand response can participate as either a demand-side resource (dispatching during the hours of highest reliability risk and reducing the need for an LSE to procure reliability credits) or as a supply-side resource (selling forward reliability credits into the FRM and incurring a real-time performance obligation). In either case, demand response resources are able to compete on a level playing field to provide reliability relative to other resources. Additionally, LSEs that are able to reduce or eliminate their load during the hours of highest reliability risk can reduce or eliminate any allocation of FRM costs.
Performance Credit Mechanism (PCM)	
Strong ability to facilitate demand response	Under PCM framework, demand response can participate as either a demand-side resource (dispatching during the hours of highest reliability risk and reducing the need for an LSE to procure performance credits) or as a supply-side resource (dispatching to produce performance credits). In either case, demand response resources are able to compete on a level playing field to provide reliability relative to other resources. Additionally, LSEs that are able to reduce or eliminate their load during the hours of highest reliability risk can reduce or eliminate any allocation of PCM costs.
Backstop Reliability Service (BRS)	
Strong ability to facilitate demand response	Under a BRS framework, demand response can participate as a demand-side resource (dispatching during the hours of highest reliability risk and reducing an LSE's allocation of BRS costs). Additionally, because BRS preserves the scarcity pricing that is inherent to today's energy-only framework, demand response resources would still have a strong incentive to generate during hours of high reliability risk and scarcity.

Dispatchable Energy Credits (DEC)	
Strong ability to facilitate demand response	Under a DEC framework, reductions in load can reduce an LSE's obligation to procure DECs, but the hours of load reduction are only loosely aligned with hours of highest reliability risk. Additionally, because DEC preserves the scarcity pricing that is inherent to today's energy-only framework, demand response resources would still have a strong incentive to generate during hours of high reliability risk and scarcity.

7.10 Prior Precedent

Implementing any new market design necessarily requires development of new processes, procedures, and rules. Constant evaluation is necessary to ensure that the market performs as designed and there are no unintended loopholes or outcomes. Implementing a design that has been successfully implemented in other jurisdictions provides more confidence that the implementation will deliver as expected.

Table 46. Assessment of Each Design's Precedent in Other Markets

Load Serving Entity Reliability Obligation (LSERO)	
Significant precedent	Bilateral resource adequacy markets that resemble the structure of the LSERO have been implemented in the California (CAISO) and U.S. Great Plain (Southwest Power Pool) electricity markets.
Forward Reliability Market (FRM)	
Significant precedent	Centralized forward capacity markets that resemble the structure of the FRM have been implemented in New England (ISONE), New York (NYISO), and Mid-Atlantic (PJM) electricity markets.
Performance Credit Mechanism (PCM)	
No precedent	A PCM mechanism has not been implemented in any electricity market in the world to-date.
Backstop Reliability Service (BRS)	
Moderate precedent	While an electricity strategic reserve that resembles the BRS has not been implemented in any U.S. electricity markets to-date, it has been implemented in several European markets.[51] The U.S. has implemented similar mechanisms in non-electricity markets, including the Strategic Petroleum Reserve.
Dispatchable Energy Credits (DEC)	
No precedent	A DEC mechanism has not been implemented in any electricity market in the world to-date.

[51] https://www.eprg.group.cam.ac.uk/wp-content/uploads/2021/04/2109-Text.pdf

8 Additional Considerations and Implementation Options

Implementing any new market design will require a number of decisions on specific issues beyond what is captured in the quantitative and qualitative analysis presented in this study. This section outlines key additional considerations and implementation options associated with each market design, as well as pros and cons associated with each option.

8.1 Load-Serving Entity Reliability Obligation (LSERO) and Forward Reliability Market (FRM)

The most significant additional considerations and implementation options are similar for the LSERO and FRM. Hence both options are described together in this subsection, with details that apply to only one or the other identified separately. The key considerations are:

- Resource accreditation
- Allocation of system need to LSEs
- Generator performance penalties
- LSE compliance penalties
- Zonal/geographic construct
- Seasonality
- Forward procurement timing
- Market power mitigation

8.1.1 Resource Accreditation

The LSERO and FRM as presented in this study accredits resources based on their availability during hours of highest reliability risk, measured as the hours of lowest incremental available operating reserves. These hours are typically, but not exclusively, aligned with peak net load hours as illustrated in Figure 35. This approach is consistent with a marginal effective load carrying capability (ELCC) approach as is being implemented in the NYISO[52] market and likely in the ISONE[53] market. As the portfolio transitions to higher penetrations of renewable energy and storage, hours of highest reliability risk will increasingly occur in periods of prolonged low renewable generation, diminishing the resource accreditation value of renewable and storage resources. This phenomenon of diminishing returns is well established in the electricity sector.[54]

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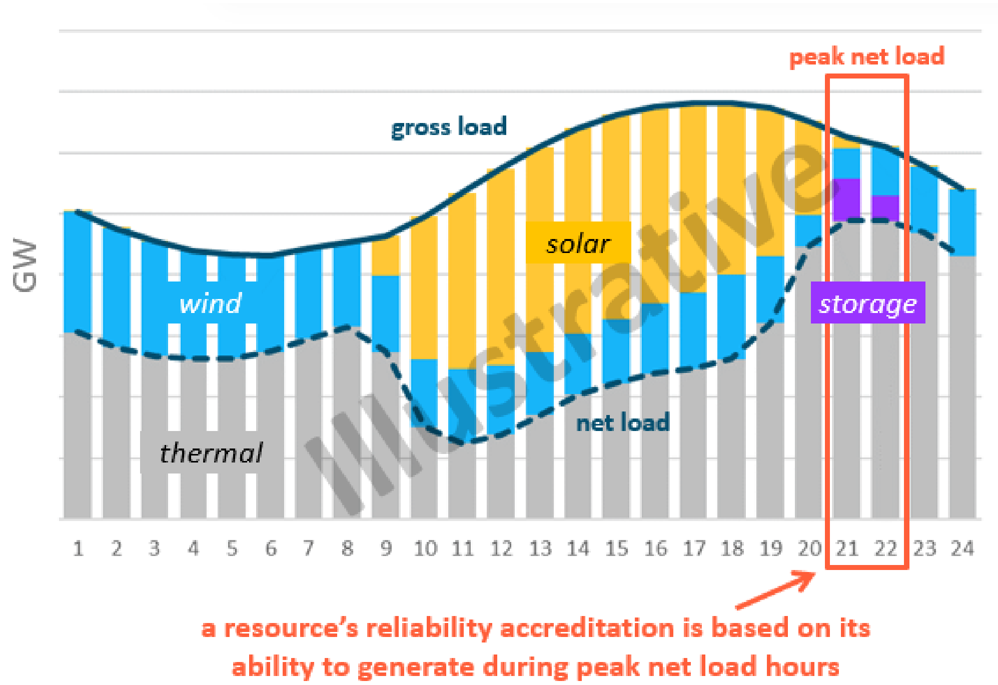
[52] https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf.
[53] https://www.iso-ne.com/static-assets/documents/2022/10/a09e_mc_2022_10_12-13_rca_iso_scope_memo.pdf.
[54] For example, see page 5 https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

Figure 35. Illustration of Resource Accreditation



There are two potential approaches toward resource accreditation that could be implemented in the LSERO and FRM designs: an ERCOT centralized marginal ELCC accreditation approach or a generator self-accreditation approach. The presence of a strong performance assessment program (that penalizes resources for non-performance relative to their accreditation) means that resources will naturally be disincentivized to seek over-accreditation. It is possible under such a construct to allow generators to self-accredit based on their own expectations of availability during hours of highest reliability risk. As shown in

Table 47, both an ERCOT centralized accreditation approach and generator self-accreditation approach requires developing the same loss-of-load-probability model and making assumptions about resource performance. This exercise determines the hours of highest reliability risk that ultimately drive system reliability requirements. Thus, a centralized ERCOT accreditation approach is not significantly less complex (or assumptions driven) than a self-accreditation approach.

Table 47. Analytical Steps in Centralized ERCOT vs. Generator Self-Accreditation

	ERCOT Accreditation		Generator Self-Accreditation
Input Development	Develop inputs of loads under a wide array of weather and other uncertainty factors	Same	Develop inputs of loads under a wide array of weather and other uncertainty factors
	Develop inputs of generator characteristics including renewable profiles, forced outage rates, and energy duration limitations	Same	Develop inputs of generator characteristics including renewable profiles, forced outage rates, and energy duration limitations
	Run loss of load probability (LOLP) model to determine hours of peak net load	Same	Run LOLP model to determine hours of peak net load
Reliability Need Determination	ERCOT utilizes load values during peak net load hours to set total reliability requirement	Same	ERCOT utilizes load values during peak net load hours to set total reliability requirement
Resource Accreditation	ERCOT utilizes generator availability during peak net load hours to determine accreditation	Different	Individual resources self-accredit based on availability during peak net load hours to determine accreditation

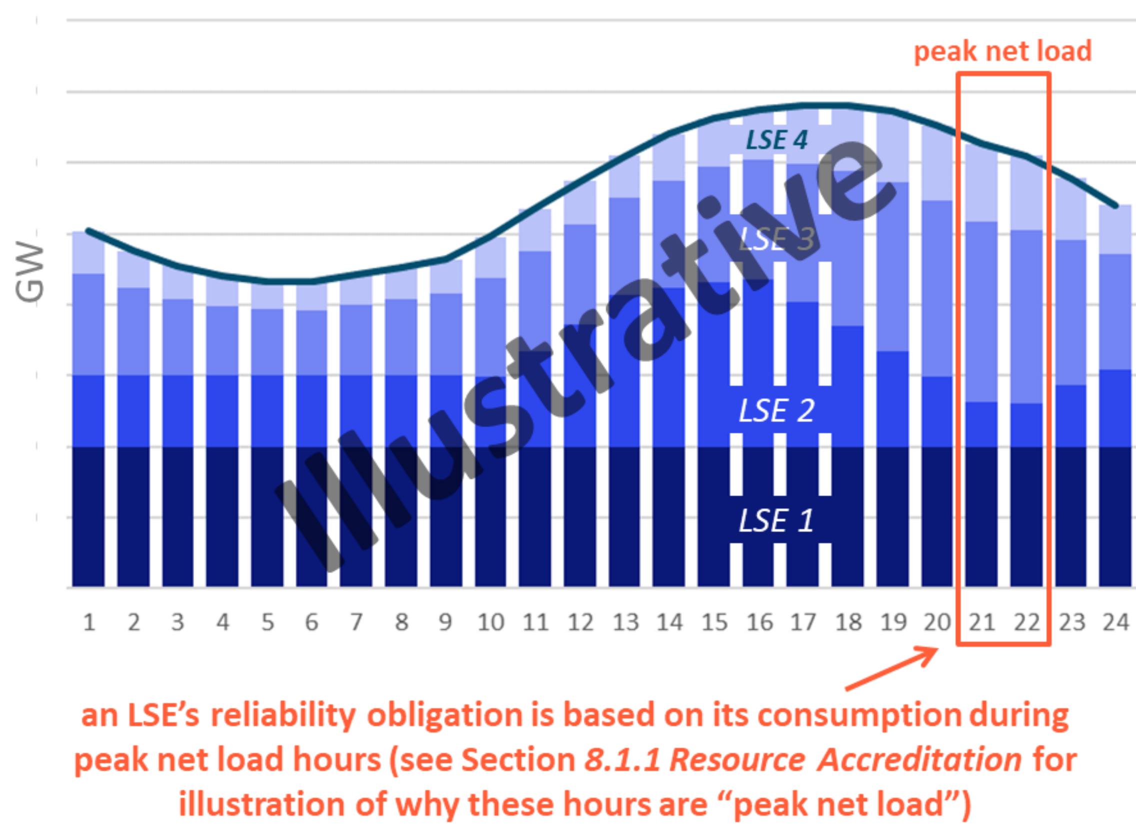
All U.S. markets with a reliability mechanism use a centralized accreditation process so this has the benefit of being a tested and proven feature. Additionally, centralized accreditation gives ERCOT and the PUCT strong confidence that there are sufficient resources to meet reliability requirements without relying on generator self-assessments. A drawback of a centralized approach is that it introduces an additional administrative step into the process.

A self-accreditation approach has the benefit that it removes an administrative step in the process. However, a self-accreditation approach may not give ERCOT the strong confidence that there are actual sufficient resources on the system to meet the target reliability standard. Furthermore, there is no precedent of the successful implementation of a self-accreditation scheme, opening the potential for unintended consequences or gaming. Additionally, self-accreditation also opens the potential significant risk of generator under-accreditation for pivotal suppliers, which is a form of physical withholding that could increase the price of reliability credits above competitive levels.

8.1.2 Allocation of System Need to LSEs

The LSERO and FRM designs set reliability credit obligations for each LSE based on their load during hours of highest reliability risk, typically aligned with peak net load. This is aligned with the principles of cost causation. It is important to note that these hours are increasingly *not* expected to be the same hours of peak gross load as illustrated in Figure 35. These hours would be determined identically to the hours used to assess resource performance, the 30 hours per year with lowest additional available operating reserves. LSEs that are able to reduce or even eliminate their load during these hours would be assigned lower or even zero reliability credit obligations. This creates a strong economic signal for demand response that both decreases total system reliability requirements and cost and is similar to the 4 Coincident Peak (4CP) mechanism that is used to allocate transmission costs and should be familiar to ERCOT market participants. However, unlike the 4CP transmission cost allocation method, the LSERO and FRM would not result in cost-shifting between LSEs because a reduction in load during the hours of highest reliability risk would reduce total system costs and allow the LSEs responsible for this reduction to capture those benefits. An illustration of how total system reliability requirements would be allocated to each LSE is illustrated in Figure 36.

Figure 36. Illustration of LSE Reliability Obligation Determination



LSE reliability obligation determination would need to occur on either an ex-ante forecast basis (in LSERO) or ex-post actual basis (in FRM). An ex-ante basis requires forecasting each LSE's load during hours of highest reliability risk. The two primary challenges that arise that it 1) creates an incentive for LSEs to under-forecast their loads so that they incur lower costs and 2) would need true-ups to account for load migration that might occur between LSEs during the period between the forward determination and the compliance period. In the LSERO framework, ERCOT would need to be equipped to audit LSE forecasts to ensure that they are reasonable and accurate and establish a mechanism for shifting of reliability obligations in the event of load migration.

8.1.3 Generator Performance Penalties

A performance penalty mechanism for generators is necessary to ensure that resources perform in a manner that is consistent with how they were accredited for reliability under the LSERO or FRM construct. Additionally, such a mechanism is also required by Senate Bill 3 that directs the PUCT to develop "appropriate qualification and performance requirements… including appropriate penalties for failure to provide these services." Properly structured financial penalties can serve as a check on the accreditation process as resources will not want to be over-accredited because it means they will be held to a higher performance standard. Put another way, the goal of a properly structured performance penalty mechanism is not that they are utilized frequently but that they ensure that the resource accreditation process is accurate.

There are two key components of developing a generator performance penalty mechanism 1) determine what hours the generator is being assessed and 2) determine what the penalty is for underperformance. Table 48 evaluates different options for each of these key components.

Table 48. Evaluation of Assessment Hours and Underperformance Penalties

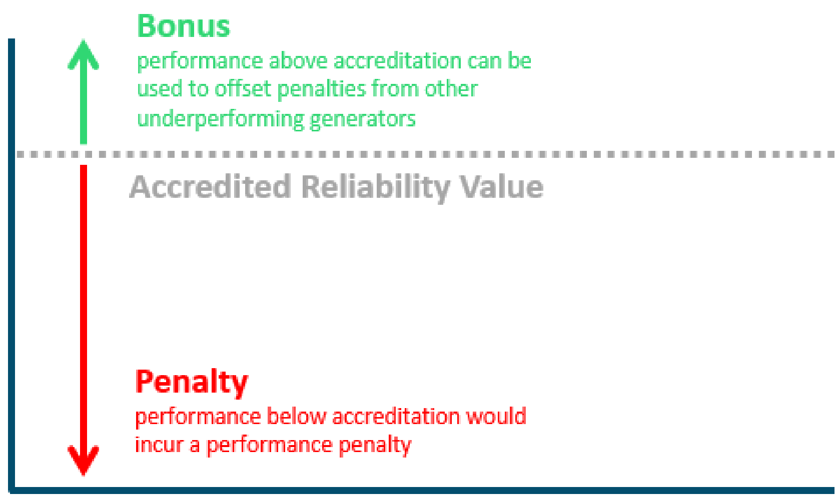
Assessment Hours	Underperformance Penalty
+ **Should be focused on the hours of highest reliability risk each year, consistent with the hours used to accredit resources** • ~30 hours/year strikes a balance between actual expected loss of load hours (~3 hr./year) and including too many hours which are inherently less impactful on system reliability (as would be the case if hundreds of hours were included) + **Should be stable in quantity each year so that generators know they *will* be assessed and held accountable to their accreditation standard** • Without consistency, generators may seek over-accreditation if they expect there will be few hours that are assessed for performance in a given year	+ **Underperformance penalties should be high enough to deter resources from seeking over-accreditation but not so high as to impose undue risk and prevent resources from participating the reliability market** + **A standard basis that balances these two objectives ties the underperformance to the cost of new entry (CONE)** • In other words, a generator that is not available during all scarcity hours of the year would be penalized CONE – a generator that is available during 50% of scarcity hours would be penalized 50% of CONE • If there are 30 assessment hours/year, this would yield a penalty price of approximately ~$3,000/MWh (~$90,000 CONE / 30 hours)

Performance assessment hours would be determined ex-post at the end of the compliance period (i.e., season or year) by looking at the 30 hours with the highest reliability risk, defined as the hours with the lowest additional available operating reserves. These hours cannot be determined in advance and are a function of real-time system operating conditions, although they are likely to occur in hours with the highest loss of load probability risk. An illustration of potential performance assessment hours is provided in Figure 37.

Figure 37. Illustration of Performance Assessment Hours

In each hour that is deemed a performance assessment hour, the availability of each reliability resource as measured by its real-time energy/AS offer is compared to its accredited reliability value. Underperforming resources are penalized at the penalty rate, while overperforming resources can be used to offset penalties from other underperforming resources in the portfolio. This reward for overperformance is important to ensure that resources are maximally incentivized to offer full capabilities into the market. This penalty and bonus assessment mechanism is illustrated in Figure 38.

Figure 38. Illustrative Bonus and Penalty Dynamics of LSERO and FRM



In the event that ERCOT collects net penalty payments from generators (meaning the portfolio as a whole underperformed its aggregate accreditation), ERCOT will refund these payments to LSEs, representing refunds for reliability that was purchased but not provided.

This performance assessment structure is similar to the performance assessment structures that are active in the ISONE and PJM markets. The key difference is that the other markets only trigger performance assessment penalties when real-time reserves drop below a pre-specified threshold. This leads to the effect that a system that is reliable (an intended outcome) will rarely experience performance assessment events and generators can expect that the risk of penalties is low. The LSERO and FRM options makes a material improvement compared to the PJM and ISONE markets in this regard. An overview of the performance assessment structures that exist in PJM and ISONE is provided in Table 49.

Table 49. Evaluation of Assessment Hours and Underperformance Penalties

ISO	Performance Penalty Structure
ISONE	+ Pay-for-performance ($/MWh) structure + $2,000/MWh initially, increasing to $5,455/MWh by 2024 + Triggered when reserves fall below pre-specified requirements + Applied to the difference between actual production MW and capacity obligation MW + Payments can be positive or negative + Stop-loss limited to auction starting price, which is higher than CONE (~$17/kW-mo.)
PJM	+ Non-performance penalty applied during "performance assessment hours" when certain emergency conditions exist + Penalty price based on net-CONE and assumes 30 performance assessment hours per year + Example: $100,000/MW-yr net-CONE / 30 hrs./y. = $3,333/MWh + Resources can receive bonus payments if they over-perform + Annual stop-loss limited to 1.5x net-CONE

8.1.4 LSE Compliance Penalties in LSERO Framework

An LSE compliance penalty mechanism is necessary to ensure that LSEs comply with the obligations of the LSERO in a bilateral framework. On the other hand, compliance penalties are not required in the FRM since LSEs are simply assessed their share of total FRM costs at the end of the operating year. As with the generator penalty mechanism, the goal is not that these penalties would be assessed but rather that they are sufficient to ensure compliance. LSE compliance penalties also serve as a tool to mitigate market power in a bilateral framework as the penalty price effectively serves as a price cap for reliability credits as an LSE can always incur the penalty price instead of procuring reliability credits from generators. It is necessary that any LSE compliance penalty be set higher than the expected competitive price of reliability credits in order to ensure the provision of sufficient reliability resources. This could be accomplished through a penalty price tied to gross CONE.

If LSE compliance penalties were assessed, this would necessarily imply a shortage of reliability resources or lack of market liquidity. ERCOT could use these funds to procure emergency backstop generation on behalf of non-compliant LSEs. Emergency resources would need to be quickly procurable – such as diesel generators, battery storage, or demand response resources – that could be brought online without significant permitting or constructing time. ERCOT would not own any backstop contracted generation but would simply serve as the vehicle to contract for these resources from the competitive market. There is precedent for ISO procurement of backstop capacity if needed for reliability in other markets.[55]

8.1.5 Zonal/Geographic Construct

A reliable electricity system requires not simply that there is sufficient total quantity of supply to meet demand but that the supply is deliverable to demand over the transmission system. In order to ensure

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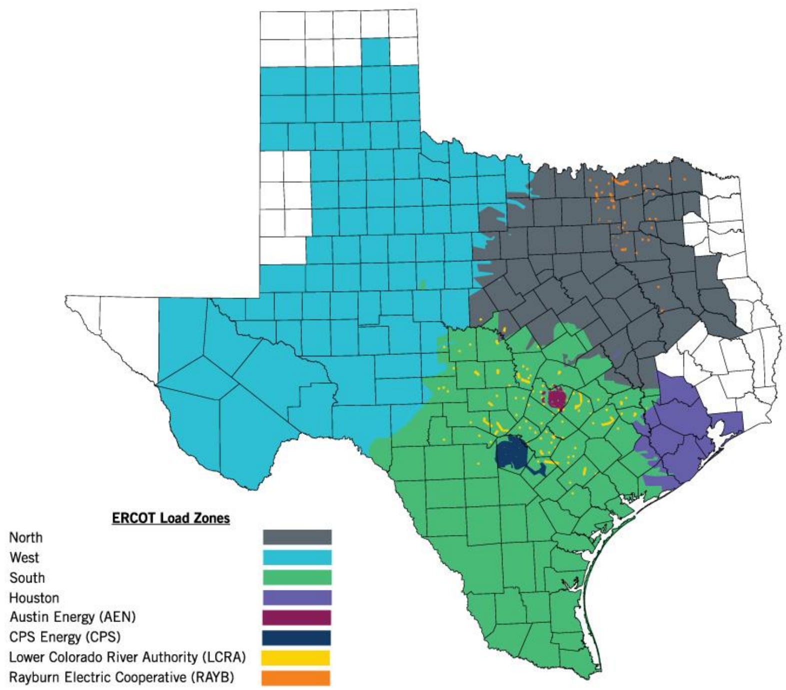
[55] http://www.caiso.com/Documents/MSC-Opiniononreliabilitymustrunandcapacityprocurementmechanismenhancements-Mar20_2019.pdf; https://www.utilitydive.com/news/ferc-approves-cost-recovery-for-exelons-mystic-gas-plant/544978/.

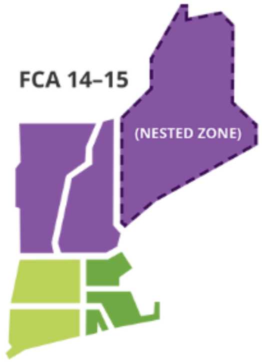
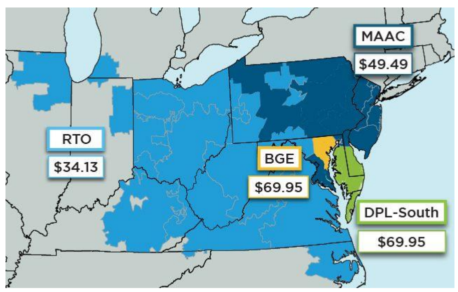
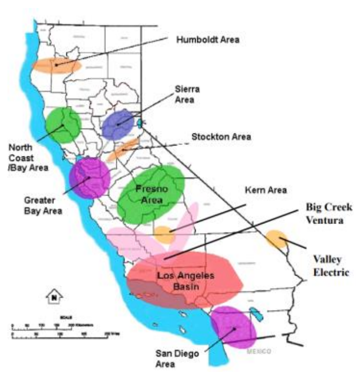
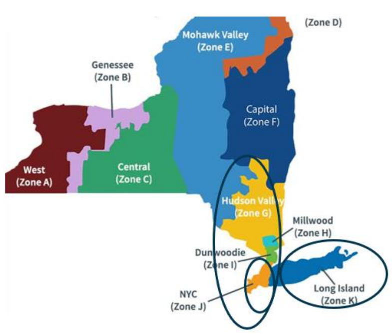
that reliability resources locate in geographies where they are needed near loads (as opposed to areas where there is not sufficient transmission capability to deliver these resources), ERCOT would need to set zonal reliability requirements. This study analyzes the ERCOT system as a "copper sheet" without transmission constraints, although ERCOT would need to incorporate these constraints into LSE reliability obligation requirements when implementing the LSERO or the FRM. ERCOT load zones, shown in Figure 39, provide a reasonable expectation for potential zones that could be implemented in the LSERO and FRM designs.

Figure 39. Current ERCOT Load Zones



All other U.S. markets with a reliability mechanism utilize a zonal or geographic construct as illustrated in Table 50.

Table 50. Jurisdictional Review of Zonal/Geographic Construct

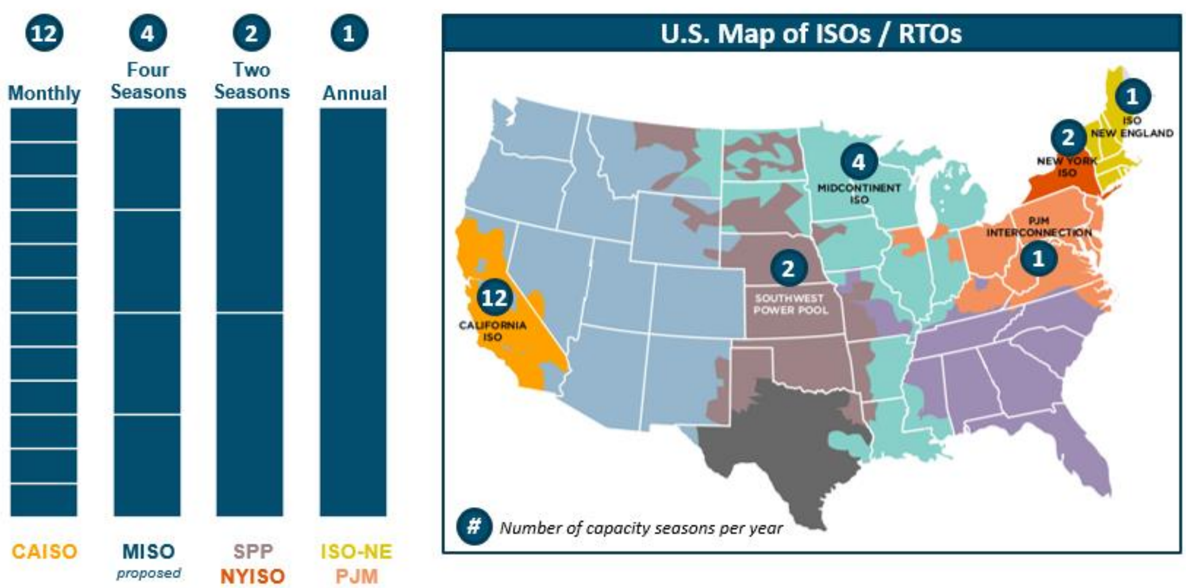
Zone	Map	Recent Market Prices *($/kW-month)*	Description
ISO-NE		NNE: $2.53 SENE: $2.64 Rest of Pool: $2.59	ISO-NE establishes capacity zones on an annual basis which results in different capacity zones in each auction
PJM		System: $1.04 Highest Zonal Price: $2.13 (DPL-South & BGE)	Import limitations and high load has typically resulted in PJM's eastern regions clearing higher than western regions
CAISO		System: $4.75 Highest Zonal Price: $7.75 (Stockton)	Although system RA needs are set by the CPUC, LCRs are determined by CAISO transmission studies
NYISO		Upstate: $3.32 Highest Zonal Price: $6.71 (Long Island)	Constraints downstate have resulted in LCRs in the Hudson Valley, New York City, and Long Island

MISO		Zones 1-7: \$7.22 Zones 8-10: \$0.09	Each of MISO's 10 load resource zones is allocated its share of the MISO-wide requirements, though most zones typically clear in groups

8.1.6 Seasonality

This study conducts all analysis and presents results on an annual basis and accounts for the reliability risk across all seasons. However, it would also be possible to implement the LSERO, FRM, or PCM designs on a seasonal basis. Other U.S. markets with a reliability construct approach seasonality differently, with some markets procuring resources on an annual, seasonal, or monthly basis as illustrated in Figure 40. Senate Bill 3 specifies that resources be "able to meet continuous operating requirements for the season in which their service is procured", and some have argued for the economic benefits of a seasonal construct.[56] E3 believes that either a properly implemented annual construct that accounts for risks across all seasons or a full seasonal construct would be consistent with the directive of Senate Bill 3 and yield similar economic outcomes.

Figure 40. Jurisdictional Review of Seasonal Reliability Constructs



[56] https://www.brattle.com/wp-content/uploads/2021/05/13723_opportunities_to_more_efficiently_meet_seasonal_capacity_needs_in_pjm.pdf.

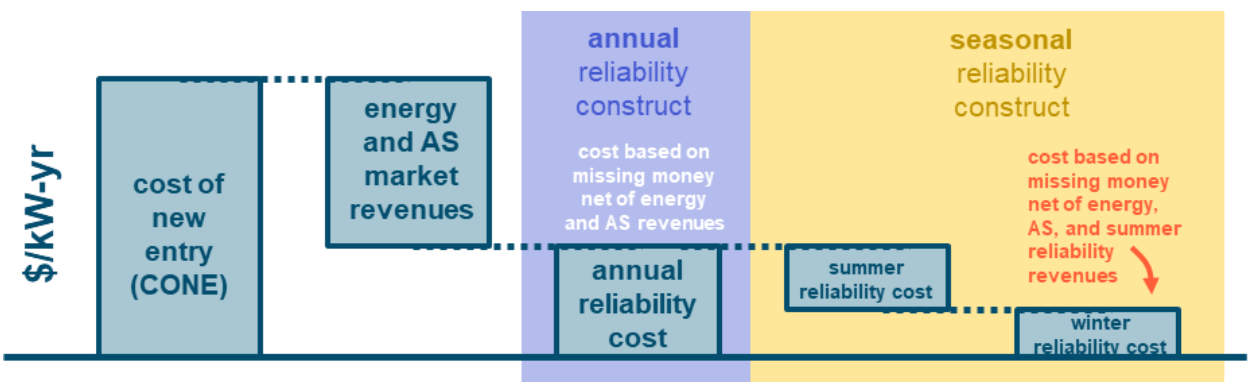
Table 51 below demonstrates how a seasonal LSERO and FRM approach might differ from an annual reliability approach and which components are affected.

Table 51. Overview of Differences Between Annual and Seasonal Reliability Construct

Component	Annual Reliability Construct	Seasonal Reliability Construct
Seasonal Definition	Annual: Jan – Dec	Winter: Oct – Mar Summer: Apr – Sep
Reliability Requirement	Annual value: load plus reserve margin during hours of highest scarcity across entire year	Separate summer and winter values: each defined as load plus reserve margin during hours of highest scarcity within each season
Resource Accreditation Values	Annual value for each resource: each value based on performance/availability hours of highest scarcity across entire year	Separate summer and winter values for each resource: each value based on performance/availability hours of highest scarcity within each season
Prices	Annual price of reliability credits	Separate summer and winter price for reliability credits (it is expected that the sum of these values would equal the annual price)

Even under a seasonal implementation approach, prices would be expected to clear in a manner that generators earn the same total annual revenues through the LSERO or FRM construct as illustrated in Figure 41. In both cases, price formation across the entire year would equal the long-run net cost of new entry, which is referred to "missing money" in Figure 41. Missing money is the additional money that a generator would need to get paid to recover its full investment cost and ongoing cost operational cost.

Figure 41. Illustration of Annual vs. Seasonal LSERO and FRM Price Formation



8.1.7 Forward Procurement Timing

The LSERO and FRM market designs procure sufficient reliability resources to meet target reliability on a forward basis, similar to other U.S. markets with a reliability market product. Forward procurement means resources are procured in advance of the compliance period, which in this study is assumed to be a one-year annual period. There are multiple options for forward procurement timing, ranging from multiple years in advance (e.g., 3 years) to a prompt procurement that occurs immediately before the start of the compliance period. Figure 42 illustrates bookend forward procurement timing options.

Figure 42. Illustration of Forward Procurement Timing Options

A multi-year forward procurement construct provides the most amount of time to both identify and rectify any reliability deficiencies, including the option for ERCOT to procure backstop resources for non-compliant LSEs in an LSERO framework. However, forward requirements also provide the highest uncertainty about future reliability requirements (driven by both load forecast uncertainty and expected resource portfolio uncertainty that drive the hours of highest reliability risk). A prompt procurement framework provides the most certainty about expected loads and resources but provides the least ability to rectify any identified reliability deficiencies, including ERCOT's ability to secure backstop generation.

Forward procurement timing also has implications for resource participation in the LSERO and FRM designs. A multi-year forward market provides the opportunity for resources to bid that do not yet exist but that could enter the market if the price rises to a sufficient level. While this can provide a signal to incentivize new resources to enter the market, it also presents risk. If the resources that clear a forward market that experience issues such as unexpected development delays, then that would leave these resources with a performance obligation that they cannot meet. Additionally, it is unlikely that a multi-decade investment such as a power plant would be made on certainty of a single year forward price, given that the majority of costs would still be recovered in future years where the reliability credit price is uncertain. These issues are currently being discussed in other markets.[57]

Other U.S. electricity markets with a reliability mechanism have implemented various flavors of forward procurement, described in Table 52 below.

Table 52. Jurisdictional Review of Forward Procurement Requirements

ISO	Market Type	Forward Procurement Timing *(100% of obligations)*	Additional Requirements
CAISO *(CPUC)*	**Bilateral**	1-Month Forward	+ **3-Yr Forward:** Must meet 50% of its obligation + **1-Yr Forward:** Must meet 90% of its obligation
MISO	**Auction (LSEs)**	1-Year Forward	+ N/A
SPP	**Bilateral**	1-Year Forward	+ Some states have earlier goals for partial obligation (percentage of total obligation)

[57] For example, see page 43 https://www.iso-ne.com/static-assets/documents/2022/06/iso-ne-2021-som-report-full-report-final.pdf.

ERCOT	**N/A**	N/A	✚ N/A
PJM	**Auction (ISO)**	3-Year Forward	✚ **1-Yr / 1-Mo Forward:** Has incremental auctions in case capacity suppliers need to change commitments, and for PJM to adjust based on changes in reliability requirements
NYISO	**Auction (ISO)**	Spot	✚ **6-Mo Forward:** Voluntary auction #1 to buy capacity earlier ✚ **1-Mo Forward:** Voluntary auction #2
ISO-NE	**Auction (ISO)**	3-Year Forward	✚ **1-Yr Forward:** ***<u>Supplier</u>*** reconfiguration auction #1 (allows for generators to change their commitment) ✚ **1-Mo Forward:** ***<u>Supplier</u>*** reconfiguration auction #2

8.1.8 Market Power Mitigation

Market power can be exerted by market sellers (or buyers) who can economically or physically withhold supply and increase prices above (or below) competitive levels. A pivotal supplier is defined as a supplier who is large enough that the quantity of reliability credits that they offer into the market can affect market price. An efficient, competitive market does not have participants that are large enough to affect market price. Only entities that are "net long" on generation would have an incentive to withhold to increase prices. Market participants that are both generators and retailers (i.e., "gen-tailers") that have more retail load than generation would not have an incentive to economically or physically withhold since they are net buyers from the market. However, in the event that the market does have pivotal suppliers with the incentive to withhold, it is important that the independent market monitor (IMM) be equipped with the tools to prevent and address this outcome as it does in other ERCOT markets.

There are multiple well-established methods to mitigate the exertion of market power under either a bilateral or centralized procurement framework, described in Table 53 below. In general, E3 believes that the options available under a centralized procurement are more effective and more likely to mimic competitive market outcomes.

Table 53. Market Power Mitigation Options

Options under ***<u>bilateral</u>*** procurement framework (LSERO)	Options under ***<u>centralized</u>*** procurement framework (FRM)
✚ **LSE Compliance Penalty Price** Setting LSE compliance penalty price at CONE provides a cap on the price of reliability, since the maximum cost LSEs will incur for reliability is CONE. ✚ **Public bulletin board of all reliability product transactions**	✚ **Resource-specific price offer limits** Generator bids are limited to their forward-looking cost. However, generators can earn revenues greater than this if the market clears at a higher price. This mechanism ensures that all bids and the clearing price is competitive. ✚ **Sloped demand curve**

This option does not directly mitigate market power but facilitates transparency and visibility for IMM enforcement. **+ Standardized contract requirement** A standardized contract requirement sets a similar standard for reliability credit contracting across LSEs and generators and also allows for more effective market monitoring from the IMM	This feature provides multiple price formation benefits. Benefits include price stability and signals of an increase price of reliability as supply and demand become tighter, even if there is a slight excess in reliability resources relative to target standard. From a market power perspective, a less steep demand curve limits the price impacts of physical withholding, reducing the potential for market participants to exert market power. Note that both resource-specific price offer limits and a sloped demand curve can be implemented in conjunction with one another.

8.2 Performance Credit Mechanism (PCM)

The additional considerations and implementation options for the PCM are:

- Demand curve determination
- LSE Performance Credit obligation determination
- Generator Performance Credit production structure
- Zonal/geographic structure
- Seasonality
- Procurement timing
- Market power mitigation

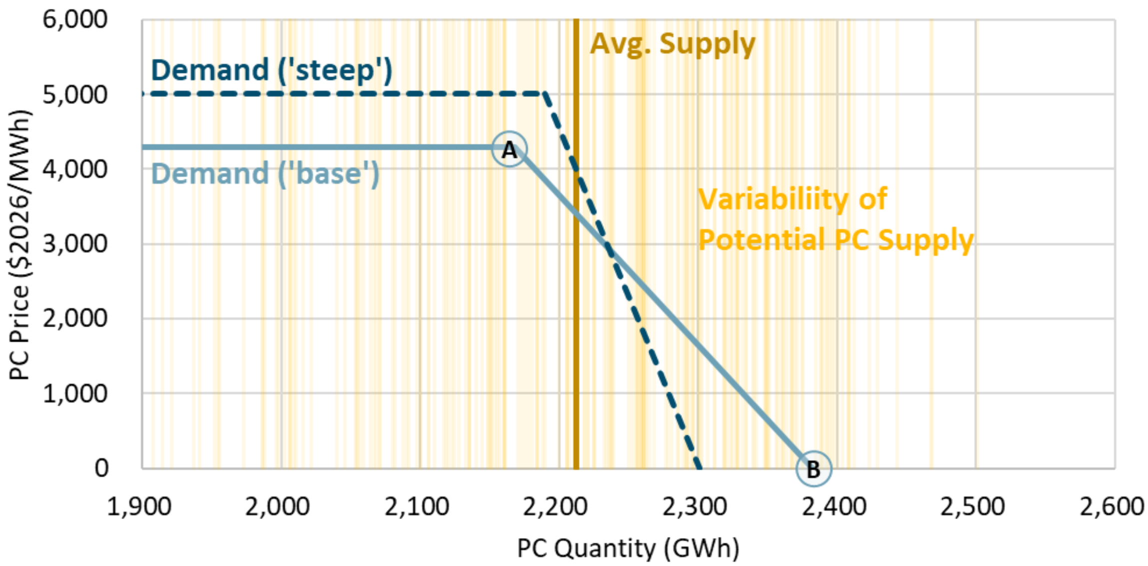
8.2.1 Demand Curve Determination

The demand curve in the PCM market design is administratively determined and is critical to ensuring that the market will yield reliability and efficient costs. Any demand curve formation should balance the following key objectives:

1. Achieve target reliability
2. Be "self-correcting" where supply above target reliability results in lower prices and supply below target reliability results in higher prices
3. Provide price stability

To a certain extent, both the first and third principle are in tension with each other. A more vertical demand curve will yield more certain reliability outcomes but less certain price outcomes, while a flatter demand curve will yield more certain price outcomes but less certain reliability outcomes. While this study assumes a demand curve that was determined to balance this achievement of target reliability and price stability ('base' demand curve), there are likely other demand curves that could also yield similar results. The base demand curve used in this study, and a more vertical demand curve ('steep' demand) are shown in Figure 43. As discussed in Section *5.2.3, Cost Metrics*, a more vertical demand curve will lead to higher inter-annual cost volatility of PCM costs / revenues, and therefore higher volatility in inter-annual generation costs.

Figure 43. Potential PCM Supply and Demand ('Base' and 'Steep') Curves



8.2.2 LSE Performance Credit Obligation Determination

The total system-wide PC requirement is based on an administratively determined demand curve that is set and fixed in advance of the compliance period, which is designed to meet the targeted reliability standard. The allocation of this system-wide requirement to each individual LSE is based on their actual usage during the top 30 hours of highest reliability risk (typically aligned with hours of peak net load) which is aligned with cost causation. In this sense, LSE obligations under the PCM market design are very similar to obligations under the LSERO and FRM. LSEs are incentivized to reduce their load during the hours of highest reliability risk in order to reduce their allocated PC requirement. This provides a strong economic signal for demand response that can lower both LSE-specific and total system load, which can ultimately lower system costs and reduce the need for reliability resources. Because LSE PC obligations are determined on an ex-post basis at the end of each compliance period based on LSE pro-rata usage, there is no opportunity for LSEs to under-forecast or game their obligations.

8.2.3 Generator Performance Credit Production Structure

Generators produce PCs by first offering PCs into the forward PC market[58] and then offering in the real-time energy and AS market during hours of highest reliability risk. This study assumes 30 hours per year where generators can produce PCs with the exact hours determined ex-post based on the hours of highest

[58] A generator can produce more PCs in the real-time market than they offered in the forward market. For this reason, this study does not assume that the forward offer requirement will impact the market outcome in any way.

reliability risk as measured by lowest incremental available operating reserves. The number of hours of generator performance is an administrative determination and should balance the factors outlined in Section *8.1.3, Generator Performance Penalties*.

8.2.4 Zonal/Geographic Structure

As with the LSERO and FRM, it will be important that resources are able to deliver energy to load. Thus, it is likely that ERCOT will want to implement a geographic component to PC production to ensure that resources are not producing PCs that are not deliverable to loads. As with the LSERO and FRM, ERCOT would need to conduct analysis to determine appropriate zonal requirements using the same considerations as outlined in Section *8.1.5, Zonal/Geographic Construct*.

8.2.5 Seasonality

This study conducts all PCM analysis on an annual basis. However, it would also be possible to implement the PCM on a seasonal or even monthly basis. The reliability and cost impacts would be similar or identical to an annual construct but with value shifted into sub-annual periods based on the reliability requirements and marginal reliability cost in each season. Seasons with sufficiently low loads (and thus low reliability requirements) or seasons with sufficiently high resource availability (and thus low marginal reliability cost) may yield very low PC prices, potentially even zero price. Seasons with higher reliability requirements or lower resource availability would yield higher PC prices. Implementing such a framework would require the development of a unique administratively determined demand curve for each sub-annual compliance period. The objective is to compensate each resource across all sub-annual periods consistently with the compensation that the resource would earn under an annual framework. These considerations are consistent with the considerations as outlined in Section *8.1.6, Seasonality*.

8.2.6 Procurement Timing

The PCM market design in this study is assumed to be structured with a voluntary forward market for LSEs to procure PCs and a mandatory residual settlement process based on load-share ratio during the assessment hours. Under this construct, during the settlement process generators get compensated on their actual PC generation in excess of what cleared in the forward market, i.e., “true ups”. E3 does not believe the forward offer requirement in this case will impact price formation in the residual settlement process since bids and offers will be based on expectations of the clearing price in the settlement process.

Alternatively, the PCM market design could be structured with a mandatory forward market, where all PCs clear in the forward market and generators incur an obligation to fulfill these obligations through production of PCs during hours of highest reliability risk. In this design, generators that overperform cannot receive compensation for additional PCs generated beyond what was sold on a forward basis but can use overproduction to offset underproduction from other generators in their portfolio. This market design is essentially analogous to the LSERO or FRM with self-accreditation, and all of the considerations that are outlined Section *8.1.7, Forward Procurement Timing* for LSERO and FRM would be applicable to this design as well.

8.2.7 Market Power Mitigation

Market power can be exerted by market sellers (or buyers) who can economically or physically withhold supply and increase prices above (or below) competitive levels. A pivotal supplier is defined as a supplier who is large enough such that the quantity of performance credits that they offer into the market can affect market price. An efficient, competitive market does not have participants that are large enough to affect market price. Only entities that are “net long” on PCs would have an incentive to withhold to increase prices. Market participants that are both generators and retailers (i.e., “gen-tailers”) that have more retail load than generation would not have an incentive to economically or physically withhold since they are net buyers from the market. However, in the event that the market does have pivotal suppliers with the incentive to withhold, it is important that the independent market monitor (IMM) be equipped with the tools to prevent and address this outcome as it does in other ERCOT markets.

The production of PCs would occur through offers into the real-time energy and ancillary services markets and thus would be subject to many of the same market power considerations that the IMM already uses to assess the competitiveness of these markets. E3 believes that the methods that the IMM uses to detect and mitigate physical withholding in these markets could also be applied to the PC market.

8.3 Backstop Reliability Service (BRS)

The additional considerations and implementation options for the BRS market design are:

+ Procurement mechanism
+ Cost allocation
+ Generator performance penalties
+ Forward procurement timing and contracting
+ Contract duration
+ Seasonality
+ Retention of energy margins

8.3.1 Procurement Mechanism

There are two primary options to procure BRS resources:

+ **Pay-as-bid:** contracted through competitive request for proposal (RFP) process
    - Each generator submits a proposal (generator characteristics and price) and ERCOT selects resources by balancing reliability contribution and cost (similar to any other proposal evaluation). All selected generators receive the price listed in their proposal
+ **Single clearing price:** developed through a centralized auction process
    - ERCOT defines specific performance criteria and generators submit bids for resources that meet these criteria. All selected generators receive the market clearing price (i.e., bid of highest cost selected generator)

The pros and cons of each of these approaches is listed in Table 54 below.

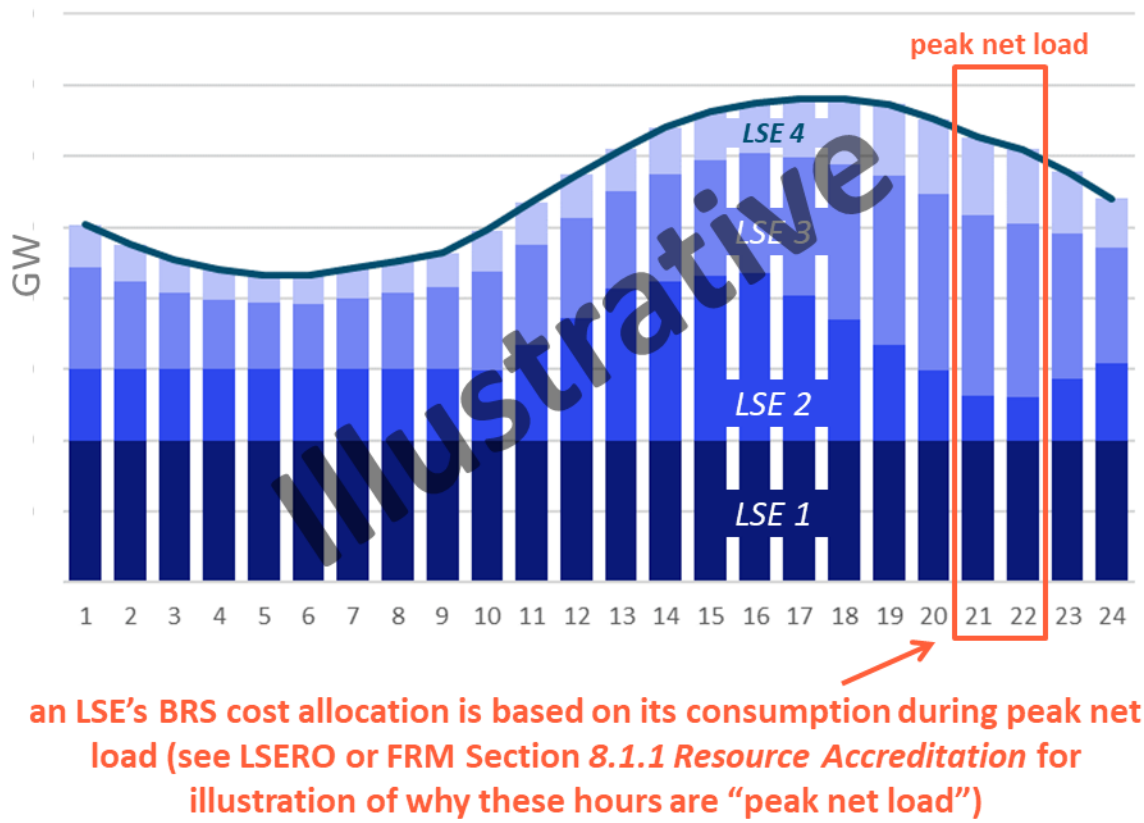
Table 54. Pros and Cons of Procurement Mechanism Options

	Pros	Cons
Pay-as-bid	+ Faster to implement because does not require defining specific characteristics for BRS product + Allows for more flexible product definition	+ Potential for resources to increase their proposed price above cost if they think they can still beat the price of other proposals (although ERCOT IMM can review BRS bids). However, an efficient market would still be expected to clear at same total cost as single clearing price mechanism
Single clearing price	+ Efficient market that encourages all generators to bid at cost to ensure they clear the market (if competitive)	+ Longer time to define characteristics and implement product

8.3.2 Cost Allocation

This study assumes that the costs of BRS are allocated to LSEs based on their load ratio share during hours of highest reliability risk, typically aligned with peak net load hours. The hours that determine BRS cost allocation are assumed to be administratively set at 30 hours per year and are determined on an ex-post basis at the end of each year by evaluating the hours with lowest incremental available operating reserves. This is aligned with the principles of cost causation because these hours drive the need for reliability and thus the BRS product. This approach is also consistent with the allocation mechanisms utilized in the LSERO, FRM, and PCM market designs. LSEs that are able to reduce or eliminate their load during these hours would be assigned reduced or even no BRS costs, creating a strong economic signal for demand response that both lowers total system reliability requirements and costs. An illustration of the hours used to allocate BRS costs is provided in Figure 44 below.

Figure 44. Illustration of BRS Cost Allocation



8.3.3 Generator Performance Penalties

A generator performance penalty mechanism is necessary to ensure that BRS resources perform when needed. The goal of performance penalties is not that they are used but rather to ensure that BRS resources perform when called upon. A generator performance penalty mechanism is required by Senate Bill 3 that directs that PUCT to develop "appropriate qualification and performance requirements… including appropriate penalties for failure to provide the services." BRS resources should be assessed on performance whenever they are called up on by ERCOT as needed for system reliability.

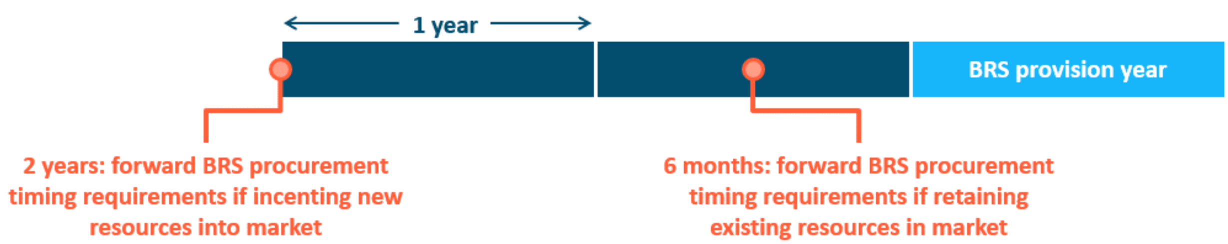
The penalty for underperformance should be stringent enough to incentivize proper investment and maintenance in the facility but not too high as to impose undue risk and prevent resources from participating in the BRS market and claw back part or all of the BRS payment. A standard basis that balances these two objectives ties underperformance to the cost of new entry (CONE). In other words, a generator that is never available when called upon would be penalized 100% of CONE, and a generator that is available during 50% of hours when called upon would be penalized 50% of CONE. If BRS resources are called upon for 10 hours/year, this would yield a corresponding performance penalty price of approximately $9,350/MWh (assuming a CONE of $93,500/MW-year). This penalty will essentially clawback the BRS revenues associated with the hours of BRS non-performance and include an incremental financial penalty on top of the clawback.

It is important to note that generators will take the potential risk of penalties into account in their bids for BRS as no generator is perfectly reliable. ERCOT should ensure that the performance standard for BRS generators is reduced to account for expected forced outages.

8.3.4 Forward Procurement Timing and Contracting

Forward procurement requirements for the BRS product should largely be based on whether the product is expected to 1) prevent retirement of existing generation or 2) incent new generation to enter the market. If the product is expected to prevent retirement of existing generation, procurement likely does not need to happen more than 6 months – 1 year in advance of the provision year, which should be sufficient to perform all necessary maintenance and ensure the resource is able and ready to perform. If the product is expected to incent new generation into the market, the procurement would likely need to happen at least 2 years in advance in order to allow for sufficient time to develop new incremental resources. It is likely the case that resources that are partially through the development (planning, permitting, etc.) could be utilized as new resources that would not necessarily be starting development from scratch. An illustration of BRS forward timing and contract is provided in Figure 45 below.

Figure 45. Illustration of BRS Forward Timing and Contracting



8.3.5 Contract Duration

ERCOT could enter into BRS agreements with generators for a single year or multiple future y ears. A single year contract structure gives ERCOT the most flexibility regarding future BRS needs and allows BRS generators to take advantage of future BRS market prices, but single year contracts may not be sufficient for new resources that need long-term commitments in order to justify significant upfront expenditures. This would likely not be a significant issue with contracts to retain existing resources. ERCOT is likely to gain significant information on the willingness of the market to enter into single year vs. multi-year contracts by soliciting requests for proposals from potential BRS generators and comparing single-year vs. multi-year costs. If multi-year costs are significantly lower than single-year costs, then ERCOT should consider longer-term agreements.

8.3.6 Seasonality

As with all other market designs, this study evaluates the BRS market design on an annual basis, where the annual opportunity costs of withholding BRS resources from the energy and ancillary service markets form the basis for price formation. In an Energy-Only market in equilibrium, this is expected to be equal to gross CONE. If BRS resources are only procured seasonally (e.g., only in winter) and they were allowed to participate in the energy market in the other season (e.g., summer), this would have the effect of suppressing scarcity pricing during the summer and reducing margins for non-BRS resources which would result in less capacity of non-BRS resources. This in turn would decrease the reliability of the system and create the need for more BRS resources to meet the target reliability standard. Therefore, seasonal procurement of BRS resources would not reduce costs while achieving a comparable level of reliability.

8.3.7 Retention of Energy Margins

The BRS design in this study is premised on the notion that BRS resources are only allowed to bid at the offer cap ($5,000/MWh) to ensure they dispatch after all other resources in the market and do not distort price formation for other resources. This assumption significantly limits the number of hours that BRS resources are expected to dispatch each year to ~6 hours/year on average. However, because these resources would dispatch when there are no other units available to meet load (bidding at the price cap), this still creates the potential for non-negligible annual margins ($30/kW-yr). There are two options for how to account for these margins 1) allow generators to retain these margins 2) allow ERCOT to retain these margins and refund the money to LSEs. In either case, the total expected BRS cost borne by LSEs is the same, because if BRS resources are allowed to retain revenues, they will include those revenue expectations in their net cost to be procured. Each option is described in more detail in Table 54 below.

Table 55. Overview of Options of BRS Energy Margins Retention

Option	Dynamic	Notes
BRS resources retain margin when dispatched	Market clearing price of BRS is CONE ($93.5/kW-yr) minus margins ($30/kW-yr)	Assumption in this study
ERCOT retains margin when dispatched	Market clearing price of BRS is CONE ($93.5/kW-yr)	ERCOT could use margins to refund load ($30/kW-yr) and offset higher clearing price of BRS; therefore, total system cost under both options would be the same

8.4 Dispatchable Energy Credits (DEC)

The additional considerations and implementation options for the DEC market design are:

- Procurement mechanism
- LSE showing timing
- DEC eligibility criteria
- DEC time window qualification

- DEC generation requirements
- System DEC requirements
- LSE compliance penalties
- Distortionary effect on energy markets

8.4.1 Procurement Mechanism

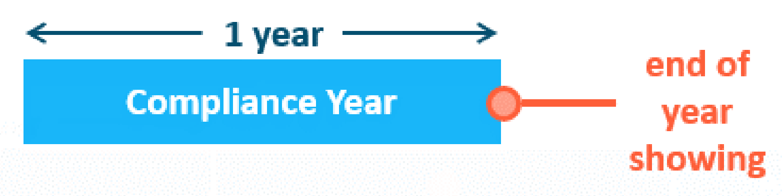
This study assumes the DEC procurement mechanism leverages the existing renewable energy credit (REC) procurement mechanisms, relying on bilateral contracting between individual LSEs and generators with a centralized entity in charge of tracking. In a DEC construct, ERCOT or another delegated agency would act as the program administrator to perform the functions of 1) resource certification and 2) centralized tracking of DEC production and DEC showings to ensure there is no double counting.

An alternative DEC procurement mechanism would be a centralized clearing structure, where demand is set based on an administratively determined sloped demand curve. The same considerations as outlined in the Section *8.2.1, Demand Curve Determination* would apply to DECs under this construct as well.

8.4.2 LSE Showing Timing

This study assumes that LSEs would make a showing to demonstrate sufficient procurement of DECs at the end of each compliance period (e.g., one year). LSEs would be able to use or "retire" DECs generated during the compliance year or during prior years that were unused and "banked." Any excess DECs from the compliance period could be banked for use in future years (up to a limit). This banking and borrowing feature of the DEC market is consistent with the REC market and provides levels of price stability if DEC production within a particular compliance period does not exactly match DEC requirements. An illustration of LSE showing timing is provided in Figure 46 below.

Figure 46. Illustration of LSE Showing Timing



8.4.3 DEC Eligibility Criteria and Generation Requirements

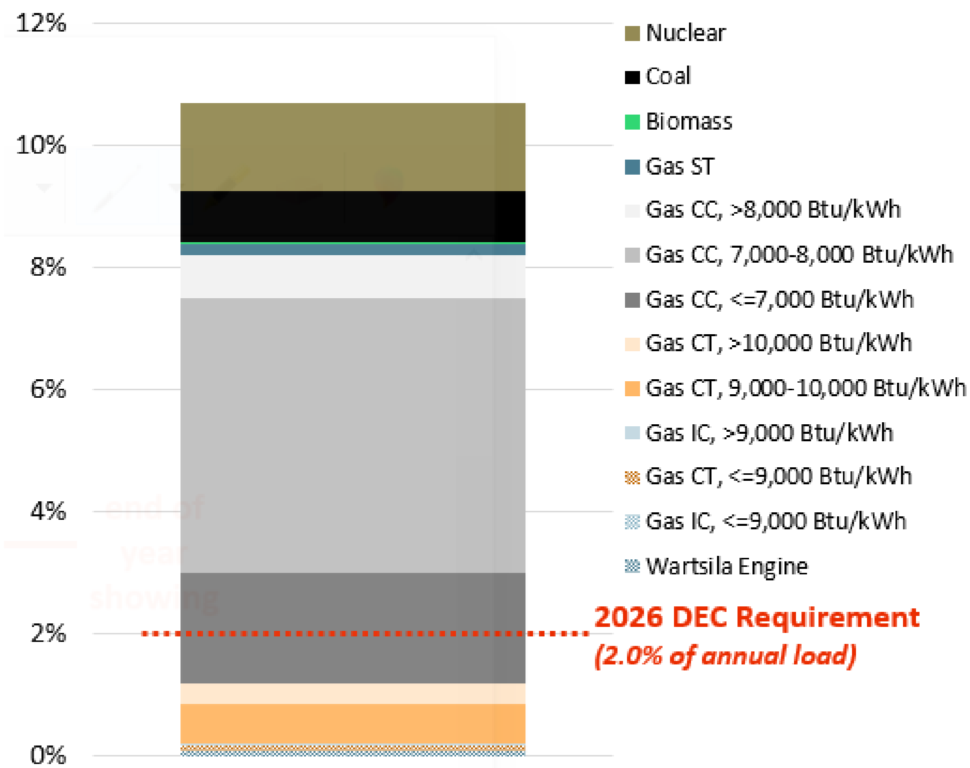
This DEC framework in this study is designed to reward resources for "dispatchability", defined as the ability to dispatch at the direction of the system operator. Defining dispatchability is an often ambiguous and debated topic within the electricity industry and inherently involves setting administrative cutoffs that may not necessarily align with a resource's contribution to system reliability. The dispatchability criteria used in this study to qualify DEC generation is defined as:

- **Ramp time:** can ramp from 0 to full capability in <= 5 minutes

- **Efficiency:** heat rate of <= 9,000 Btu/kWh
- **Duration:** can dispatch continuously for >= 48 hours

However, there are many other resources on the ERCOT system with slightly different capabilities that may provide nearly identical contributions to system reliability. If these additional resources were eligible to generate DECs, it would greatly increase the potential production of DECs over the compliance period due to the increase in potential supply. Figure 47 below shows the potential supply of DECs based on resource type, measured as a % of total 2026 annual load. In addition to resource eligibility, the size of the time window for DEC generation also has a significant impact on the potential total DEC requirement as described in the following section.

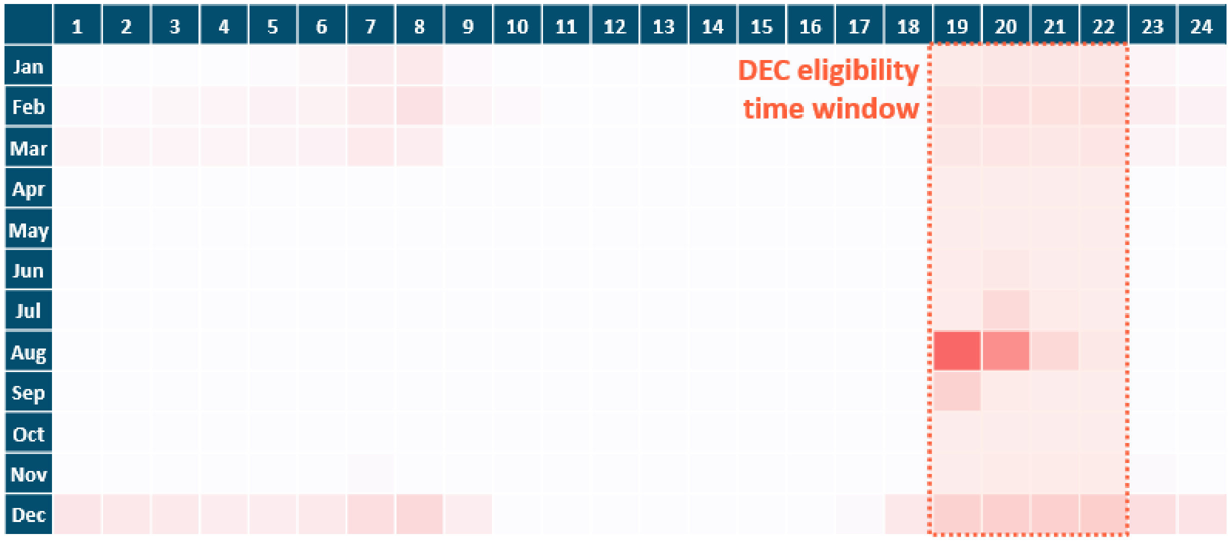
Figure 47. Potential DEC Generation by Resource Type (% of 2026 Annual Load)



8.4.4 DEC Time Window Qualification

In the DEC market design, DECs can be generated by eligible resources that clear in the energy or ancillary service markets during a pre-defined time window (6pm – 10 pm). This time window was developed to overlap hours of highest reliability risk. Figure 48 below shows a heatmap of the highest reliability risk hour for each month (row) and hour of day (column) combination. It can be seen that hours of highest reliability risk align with DEC eligibility time window. However, there is still an inherent mismatch between hours of DEC eligibility and hours of highest reliability risk because high risk hours do not occur every day, and the DEC framework rewards resources for production during these hours every day. Nonetheless, the DEC market design could expand or contract the time window. An increase in eligible hours would potentially imply a higher annual DEC generation requirement and vice versa.

Figure 48. DEC Eligibility Time Window and LOLP Heatmap



8.4.5 DEC Generation Requirements

The DEC framework is premised on the notion that eligible resources should be compensated for actual performance. This study defines performance as a DEC-eligible resource that clears in one of the following markets:

- Energy
- Regulation up
- Responsive Reserve Service (RRS)
- Non-spin

These markets were selected based on the positive contribution to reliability that resources provide in these markets but contracting or expanding which markets are eligible (such as regulation down) would imply that annual DEC requirements should increase or decrease.

8.4.6 System DEC Requirements

Setting an annual MWh DEC requirement is inherently challenging given the tenuous link between DEC resources and overall reliability, as described in Section *5.2, Alternative Market Designs*. This study assumes an annual DEC target of 2%, which is approximately equal to the number of DECs that would be produced if 5,640 MW of new DEC-eligible generation were to enter the market and clear in each eligible hour.[59] The amount 5,640 MW was selected because that is the incremental quantity of natural gas CTs that are procured by the LSERO, FRM, and PCM market designs. This study assumes that all individual LSEs will be responsible for procuring DECs equivalent to 2% of their annual load. Alternative market design

[59] (5,640 of new DEC-eligible generation + 1,260 MW of existing DEC-eligible generation) * 4 hours/day * 365 days/year * (1-5% FOR) / 470 TWh annual load = 2%.

constructs in the dimensions of DEC eligibility, DEC time window qualification, or system DEC requirements would likely impact the quantitative system portfolio, reliability, and cost results, but these results would need to be analyzed in on a case-by-case basis.

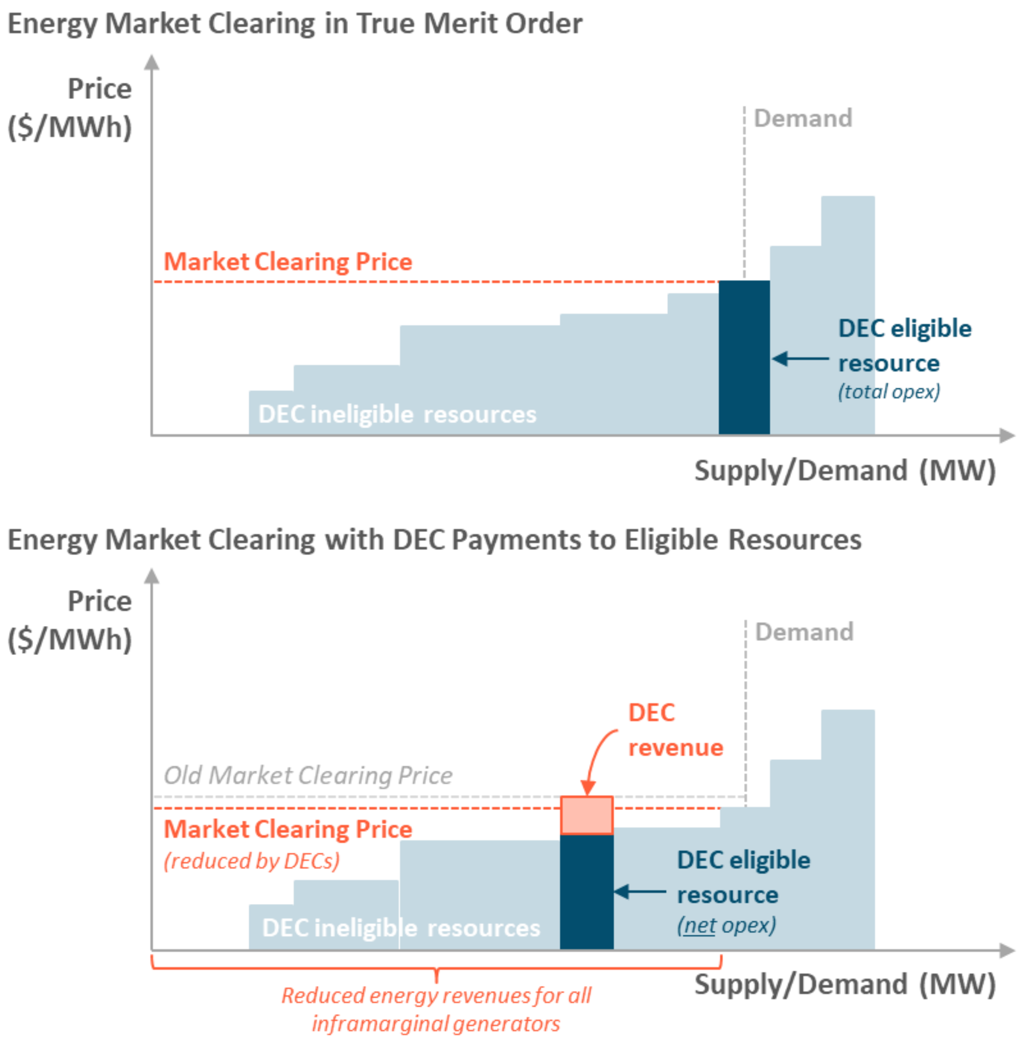
8.4.7 LSE Compliance Penalties

An LSE compliance penalty mechanism is necessary to ensure that LSEs comply with DEC requirements. As with other market designs, the goal of LSE compliance penalties is not that they are used but rather that they are sufficient to ensure compliance. An alternative feature of a DEC compliance penalty is that it serves as a price cap on the cost of DECs since LSEs can incur the penalty cost instead of procuring DECs. This study finds that $30/MWh is a reasonable value for LSE compliance penalties as it is sufficiently high enough to ensure compliance (i.e., it is in excess of the expected market price of DECs at $15/MWh), however, this penalty price could be set at higher or lower values.

8.4.8 Distortionary Effect on Energy Markets

Because DECs are generated by clearing in an eligible market during eligible hours, this creates a financial incentive for DEC eligible resources to clear in those markets. Thus, DEC resources will reduce their bids in eligible markets by the amount of the market price of a DEC, distorting the true merit order of the generation stack and potentially dispatching in place of a lower cost unit. This will additionally have the effect of reducing energy and ancillary service prices during hours when DEC resources are on the margin. Note that this is a separate and incremental impact that the presence DEC resources themselves have on the suppression of scarcity pricing due to additional dispatchable capacity on the system. This reduction in energy and ancillary service prices will have the effect of reducing margins for other non-DEC resources and result in fewer non-DEC resources in equilibrium. This price suppression phenomenon is illustrated in Figure 49.

Figure 49. DEC Price Suppression Phenomenon Overview



9 Conclusion

This report evaluates the quantitative and qualitative performance of six different market design reform options for the ERCOT market. The quantitative results yield the following conclusions and insights:

+ ERCOT's current energy-only market structure does not target a specific reliability standard, leading to a system that does not provide sufficient revenue to resources to achieve the common reliability standard of 0.1 days/yr LOLE. While today's system appears to be close to the 0.1 days/yr benchmark, under market equilibrium conditions in 2026, the Energy-Only (status quo) design results in an LOLE of 1.25 days/yr.
+ There are multiple market mechanisms that can provide the additional revenue needed to achieve higher levels of reliability due to incentives for more dispatchable resources. The Load Serving Entity Reliability Obligation (LSERO), Forward Reliability Market (FRM), Performance Credit Mechanism (PCM), and Backstop Reliability Service (BRS) designs each improve reliability relative to the Energy-Only design, based on the specified LOLE standard of 0.1 days per year. These mechanisms result in substantially similar incremental costs, representing approximately 2% of total system cost.
+ While the LSERO, FRM, PCM, and BRS designs yield similar expected total costs, their impacts on cost *variability* – the potential for costs to vary year to year based on actual system conditions – are significantly different. The LSERO, FRM, and PCM market designs reduce the variability of annual system costs by transitioning from a design that is dependent upon uncertain scarcity pricing to a design that has more stable price signals. By contrast, the BRS design seeks to preserve the volatility characteristic of today's energy-only market.
+ The dispatchable energy credit (DEC) mechanism does not yield a material improvement in system reliability and increases system cost. This design rewards resources that enter the market in response to the DEC requirements, in turn reducing revenues to non-DEC-eligible resources. This increases the likelihood that resources that cannot meet the eligibility criteria for DECs will exit the market.
+ The relative cost and reliability impacts of each market design remain stable across the "High Renewables", "High Gas Price", and "Low Cost of Retention" sensitivities, indicating that the relative results are robust to a number of key uncertainties on the 2026 system and beyond.

Because the market designs that improve reliability each increase costs by similar amounts, qualitative considerations should play a key role in the evaluation of tradeoffs among the designs. Key qualitative differences include:

+ The LSERO and FRM designs provide market mechanisms to achieve a designated reliability standard through investment in new resources and/or retention of existing ones. The designs also include performance penalties which provide resources with strong incentives to perform in real time. Generator revenues are more stable over time relative to the Energy-Only design, which may result in lower financing costs. Both designs require complex *ex ante* resource accreditation mechanisms and long implementation timelines. These designs are also better equipped to deal with extreme weather events to the extent they can be reflected accurately in the modeling that is performed for reliability need determination and resource accreditation. These designs preserve strong signals for demand-side resources to contribute to reliability. Both designs have significant prior precedent in other U.S. electricity markets.

+ The LSERO may be perceived as presenting a risk of allowing generators to exercise market power and challenges to address cost shifts related to load migration that occurs after the close of the forward compliance period. The FRM addresses both of these concerns through (1) the ability of the independent market monitor (IMM) to mitigate generator bids into the centrally-cleared market, and (2) a *ex post* reallocation of reliability credits among LSEs at the cleared price to LSEs based on actual consumption during critical hours.
+ The PCM design has similar characteristics to the LSERO and FRM but has slightly less complexity because it avoids the need for forward-looking resource accreditation. However, generator revenues are less stable than under the LSERO and FRM. The PCM is also less able to reflect infrequent extreme weather conditions because it is assessed each year based on actual conditions that may not reflect any extreme weather.
+ The BRS design constitutes the smallest change to the existing market framework by largely preserving the current energy-only market dynamics and all of the generator incentives that exist in it, including scarcity pricing and the operating reserve demand curve (ORDC). It has low risk of market power and the shortest implementation timeline of any market design that was studied. In order to retain the energy-only market construct and scarcity pricing, BRS resources would only be allowed to participate in the energy and ancillary service markets after all generation in ERCOT is exhausted; i.e., BRS resources are last in the bid stack. This limits the competitive market mechanism of this design and results in scarcity pricing when there is not true scarcity on the system. The BRS may also not be consistent with the principles of a competitive market, since it holds generation out of the market and market participants have no ability to avoid BRS costs through their own resource procurement decisions.
+ The DEC design presents a low and addressable market power risk as well as moderate complexity and potential implementation timeline. However, the DEC design provides for very limited competition among resource types, little incentive for real-time performance during the hours that matter most, and little ability to address risks related to extreme weather events.

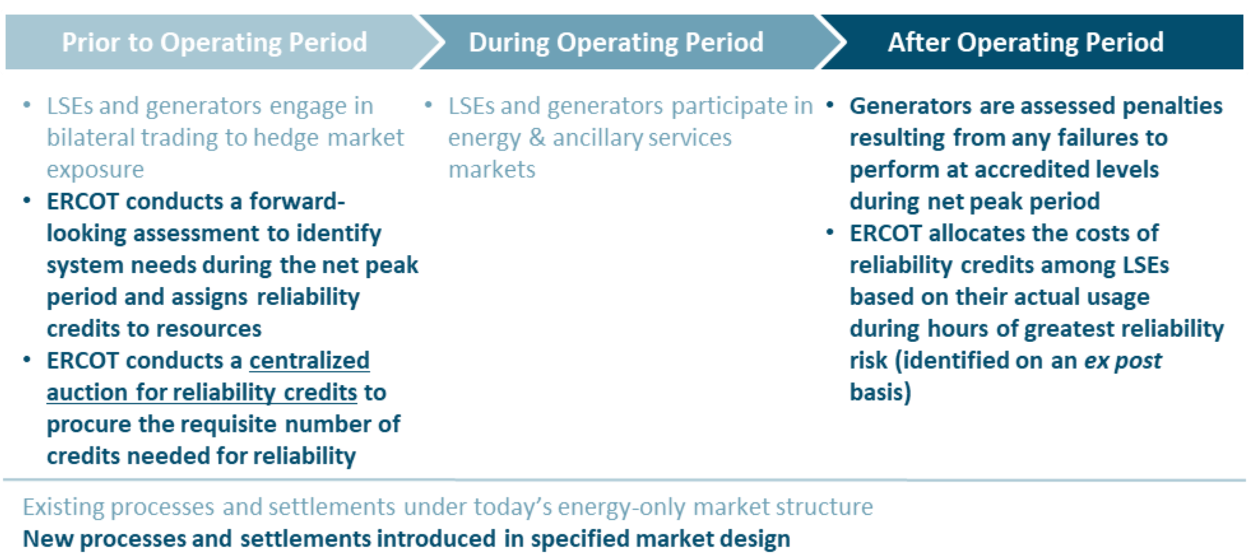
10 E3 Recommendation

The PUCT requested E3 to provide a recommended course of action for ERCOT market design reform from among the options analyzed in this report. This section describes E3's recommendation and the evaluation criteria used to develop it. The recommendations provided in this section were developed independently by E3 and do not necessarily represent the views of the PUCT Commissioners, PUCT Staff, or E3's subcontractors Astrapé Consulting. Under guidance of the Blueprint, E3 did not consider the existing energy-only market structure as a candidate for our recommendation.

Electricity market designs such as the ones described in this report necessarily involve tradeoffs and judgments about how to balance competing goals. E3's role in the quantitative and qualitative evaluation of market designs is that of an independent advisor, providing unbiased information and analysis about the various options to elucidate their key features and to highlight important differences among them under a specified set of assumptions, inputs, and views of the future. Stakeholders are expected to evaluate which options best suit their own interests as well as the interests of the ERCOT market as a whole. The PUCT and Texas decisionmakers will consider the information provided by E3 and the opinions and perspectives of stakeholders to make the difficult decisions about the tradeoffs involved in any market reform proposal. In providing this recommendation, E3 does not seek here to substitute our judgment in place of that deliberative process.

Based on the analysis conducted in this study and our broader experience in market design, E3 recommends that ERCOT implement a **Forward Reliability Market (FRM)** as described in the body of the report. The general structure of this FRM is provided in the figure below.

Figure 50: Overview of Forward Reliability Market (FRM)



E3's rationale for this recommendation is as follows:

Multiple market designs evaluated in this study appear capable of providing an improvement in market signals to ensure reliability in the ERCOT market. The LSERO, FRM, PCM, and BRS designs each yield improvements in reliability under equilibrium conditions at similar incremental costs relative to today's energy-only design. Accordingly, the choice of a recommendation among these designs is, in many respects, a decision to be made on qualitative factors and which design is perceived by the PUCT and stakeholders to be the best fit with Texas' competitive retail and wholesale markets.

E3 believes that the creation of a forward reliability product as envisaged by the LSERO and FRM offers a more suitable fit for the market. This belief stems from the following criteria:

+ **Out-of-market reliability solutions – such as the BRS – should be temporary.** Historically, the ERCOT market has relied on principles designed to encourage competition in the wholesale and retail markets. Long-term reforms should continue the goal of encouraging competition among all resources that are capable of delivering a reliable low-cost supply of electricity and promote enduring, sustainable, market-based mechanisms that facilitate efficient market outcomes. Procurement of backstop resources may be justified as a temporary solution to promote reliability goals, but should not be necessary as a permanent feature of a well-functioning, competitive market.
+ **Implementation of the PCM entails significant risk because of its novelty.** Implementing any new market design necessarily requires development of detailed business rules. In many US markets, these rules have been honed over time as flaws and unintended consequences have been exposed. Constant reevaluation is necessary to ensure that the market performs as designed. No market mechanism of this type has been implemented in any wholesale market, and while E3 has analyzed this design's impacts on the market based on the parameters set forth by the PUCT, the potential for unintended consequences or unexpected challenges in the definition and implementation of market rules could undermine a successful implementation. In contrast, the LSERO and FRM – while unique in many ways in how they have been tailored to fit the specific context and challenges facing the ERCOT market – resemble designs that have been successfully implemented in other jurisdictions. Considerable effort has already been dedicated to establishing appropriate market rules, protocols, and procedures for implementation of the market structures.
+ **Reforms that require procurement of a forward reliability product provide more natural year-to-year stability in market outcomes.** The LSERO and FRM exhibit the lowest volatility in cost and market outcomes. This should provide for a more stable signal for investment in new resources and retention of existing resources needed to maintain reliability, discouraging "boom-and-bust" cycles of investment. This could, in turn, lower the perceived risk of participation in the ERCOT market and attract additional resource investment at a lower cost of capital. It should also lead to more stable electricity bills for ERCOT retail customers.

The LSERO and FRM market reforms – which both create a forward reliability product and require that a sufficient quantity of that product be procured to meet a target reliability standard – differ mainly in the structure of the market. The LSERO requires individual LSEs to procure their share of total reliability credits through bilateral contracting, whereas the FRM relies upon a centrally cleared auction to procure the requisite quantity of reliability credits. Between these two structures, E3 finds the centrally cleared to be a better fit for Texas' competitive market landscape for several reasons:

- **A centrally cleared market unlocks powerful tools for market power mitigation.** The bilateral nature of the LSERO provides for moderate market power risk with limited tools for the system operator or market monitor to mitigate these risks. By contrast, the FRM's centralized auction process provides for both transparent pricing and tools such as a sloped demand curve, resource-specific must-offer obligations with offer price caps, and more opportunity for oversight by an independent market monitor that can mitigate the exercise of market power.
- **A centrally cleared market can be more easily integrated into Texas' dynamic retail market.** The constant migrations of customers from one LSE to another creates uncertainty for LSEs about what their load may be in future periods. The requirement for LSEs to procure reliability credits on a forward basis in the LSERO creates challenges in accounting for load migration and introduces incentives for LSEs to game this market mechanism by underforecasting their reliability requirements because of the highly competitive nature of the ERCOT retail market. In contrast, cost allocation from a centrally cleared market to LSEs retrospectively removes the ability to game this cost. It should also be noted that in the U.S. markets with a bilateral resource adequacy construct similar to the LSERO (e.g., California, SPP, and MISO), there is limited retail choice with customers primarily being served by regulated suppliers; while many states in markets with centrally-cleared forward reliability markets offer full retail choice. In E3's prior work on ERCOT market design, it was thought that a centrally cleared market would not pass "stakeholder acceptability" criteria, however after hearing stakeholder concerns about the bilateral LSERO, E3 is convinced that many of these could be remedied through a centralized auction as described above.

Should the PUCT ultimately select the FRM as its preferred market reform, implementation of an FRM would require several implementation decisions as outlined in the report in the *Additional Considerations and Implementation Options* section. E3 recommends the following specific steps in implementing the FRM:

- **Develop reliability standard:** This standard may be tied to a number of reliability metrics including loss of load expectation, loss of load hours, or expected unserved energy and does not necessarily need to be equivalent to the 0.1 days/year loss of load expectation standard used in this report.
- **Implement marginal ELCC accreditation for all resources through a central process:** a marginal ELCC framework focuses on the hours of highest reliability risk and ensures economically efficient market outcomes. This process should be performed by ERCOT and not generator self-accreditation in order to prevent the exercise of market power through physical withholding.
- **Address extreme weather:** Ensure that load forecasting, reliability modeling and resource accreditation accounts for potential extreme weather events and reflects accurate expectations of future weather conditions.
- **Address fuel security issues:** Thermal resources are sometimes unable to perform when needed due to lack of access to fuel supplies. In some cases, the same event affects multiple generators at once. This is known as a "correlated outage". In the past this has occurred during extreme weather conditions. Lack of access to fuel can significantly reduce the resource adequacy value of thermal generators. E3 recommends incorporation of fuel security issues and correlated outages as part of the resource accreditation methodology.

- **Implement a stringent performance assessment program:** a financially stringent performance assessment program with consistent and stable application will help ensure that resources are held accountable to their accredited marginal ELCC value

Appendix A. Study Backup Data

Table 56. Detailed Energy-Only (Equilibrium) Resource Portfolio for Base

Detailed Resource Type	Resource Type [1]	Summer Capacity (MW)
Natural Gas – Combined Cycle	Natural Gas	30,687
Natural Gas – Combustion Turbine	Natural Gas	7,232
Natural Gas – Internal Combustion	Natural Gas	919
Natural Gas – Steam Turbine	Natural Gas	4,447
Coal	Coal	7,396
Nuclear	Nuclear	4,973
Hydro [2]	Hydro	372
Biomass	Biomass	163
Solar	Solar	38,379
Rooftop Solar	Solar	968
Wind – Coastal	Wind	5,900
Wind – Other	Wind	29,633
Wind – Panhandle	Wind	5,072
Storage	Battery Storage	7,411
Reserve Shed	Other	2,000
Emergency Gen	Other	470
Emergency Response Service (ERS)	Other	925
Power Balance Penalty Curve (PBPC)	Other	200
Load Resources (LRs)	Other	1,591
T&D Service Providers (TDSP)	Other	286
Private Use Networks (PUNS)	Other	4,262
4 Coincident Peak (4CP)	Other	900
Price Responsive Demand (PRD)	Other	1,500
Total		**155,684**

Notes:

1. Represents resource categorization used throughout the main body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.

Appendix B. 2022 System Details

2022 load and resource assumptions are based on the 2022 Seasonal Assessment of Resource Adequacy (SARA) report.[60] 2022 loads are assumed to be 423 TWh/year with an average peak load of 78,000 MW, a 90th percentile peak load of approximately 81,000 MW, and a maximum peak load of 85,000 MW. 2022 resource installed summer capacities by resource type are shown in Table 57. Numbers will not match 2022 SARA exactly due category SERVM accounting differences and some prolonged individual resource outages.

Table 57. 2022 Summer Capacities by Resource Type

Resource Type	Resource Type [1]	Summer Capacity (MW)
Natural Gas – Combined Cycle	Natural Gas	30,687
Natural Gas – Combustion Turbine	Natural Gas	6,285
Natural Gas – Internal Combustion	Natural Gas	922
Natural Gas – Steam Turbine	Natural Gas	10,587
Coal	Coal	13,568
Nuclear	Nuclear	4,973
Hydro [2]	Hydro	372
Biomass	Biomass	163
Solar	Solar	11,425
Rooftop Solar	Solar	567
Wind – Coastal	Wind	5,138
Wind – Other	Wind	25,828
Wind – Panhandle	Wind	4,245
Storage	Battery Storage	2,014
Reserve Shed	Other	2,000
Emergency Gen	Other	470
Emergency Response Service (ERS)	Other	925
Power Balance Penalty Curve (PBPC)	Other	200
Load Resources (LRs)	Other	1,591
T&D Service Providers (TDSP)	Other	287
Private Use Networks (PUNS)	Other	4,262
4 Coincident Peak (4CP)	Other	900
Price Responsive Demand (PRD)	Other	1,500
Total		**128,909**

Notes:

1. Represents resource categorization used throughout the main body of the report.
2. 372 MW represents SERVM's average expected hydro summer capacity over the 40 weather years based on the 572 MW of nameplate capacity in ERCOT's CDR report.

[60] https://www.ercot.com/files/docs/2022/05/16/SARA_Summer2022.pdf.

In order to engender confidence in the forward-looking 2026 reliability calculations, this study analyzes the 2022 system with current loads and resources. The results showed that the current system achieves a loss of load expectation (LOLE) of 0.03 days/year, exceeding the common industry benchmark of 0.1 days/year or “one day in ten years”. Each event is calculated to last 2.4 hours on average with a total magnitude of 2,228 MWh per event. These values are summarized in Table 58.

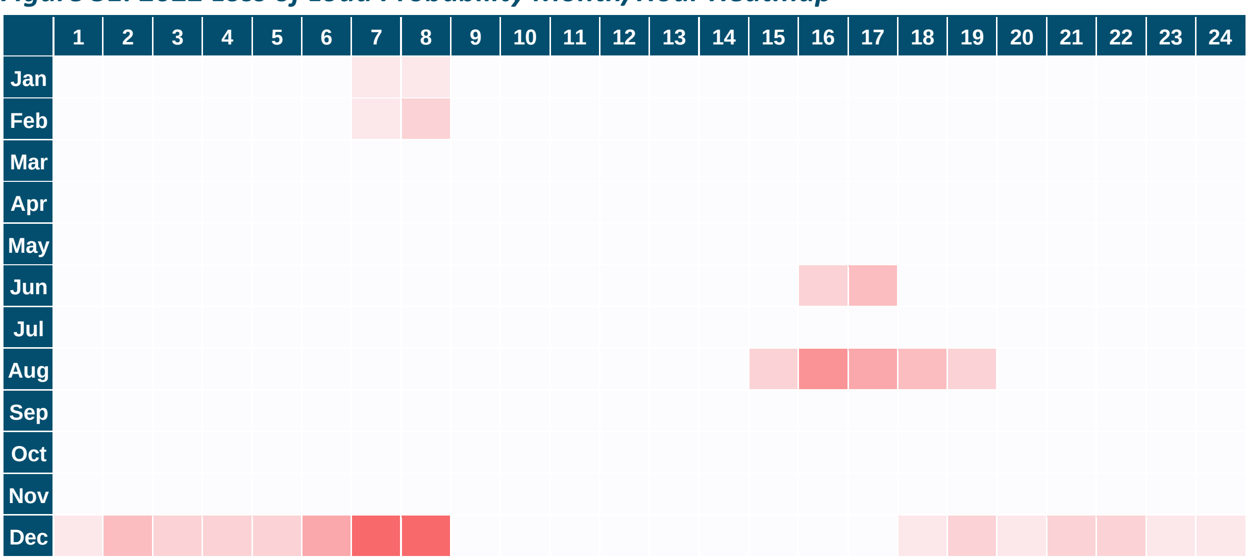
Table 58. 2022 Reliability Statistics

Reliability Metrics	2022 Pre-Equilibrium
LOLE *(days/year)*	0.03
LOLH *(hours/year)*	0.1
EUE *(MWh/year)*	66

While this finding may initially seem surprising relative to expectations, loads in summer of 2022 exceeded forecasts by over 2,300 MW[61], and the system was able to maintain reliability without shedding any firm load. This indicates that the resources today are sufficient to maintain reliability across a broad range of system conditions, assuming that 2022 summer loads actually were outliers relative to expectations. However, to the extent that ERCOT load forecasts may be structurally low, and 2022 summer loads were actually “normal” with the potential to be much higher, then the 2022 reliability results may be low (i.e., too reliable).

The hours with the highest loss of load probability occur during summer afternoon/evenings and winter mornings and nights. Figure 51 illustrates the hours of highest loss of load probability throughout the year on a month/hour basis.

Figure 51. 2022 Loss of Load Probability Month/Hour Heatmap



[61] 2022 summer peak load reached 80,037 MW, relative to a peak forecast of 77,733; Sources: https://www.ercot.com/gridinfo/load/load_hist; https://www.ercot.com/files/docs/2022/02/24/2022_LTLF_Report.pdf.

The reliability metrics presented above are annual average statistics, but loss of load does in fact occur in spurts, with some years having no loss of load and some years having more significant levels. Table 59 provides a distribution of the probability of each year having a certain number of loss of load hours. There is a 2.5% probability of at least one hour of lost load during the year, and only a 0.5% chance of 3+ hrs. of lost load.

Table 59. 2022 Distribution of Loss of Load Hours per Year

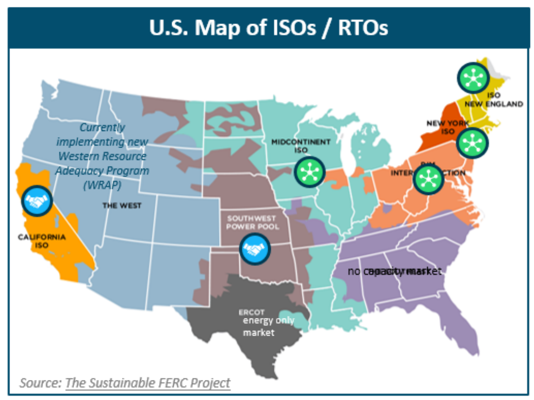
	Loss of Load Hours per Year (hours/year)			
	0	**1**	**2**	**3+**
Probability	97.5%	1.0%	1.0%	0.5%

Appendix C. Review of U.S. Electricity Market Reliability Mechanisms

Before introducing a reliability mechanism into the ERCOT market, it is important to understand how reliability me in other U.S. markets has performed. In general, there are two types of reliability markets used in the U.S. today: centralized capacity markets and bilateral resource adequacy frameworks. Centralized approaches are used in PJM, ISONE, NYISO, and MISO (hybrid), while bilateral frameworks are used in California and SPP. There is no regional reliability mechanism used in the Southeastern U.S., and while the Pacific Northwest has historically not utilized a centralized resource adequacy framework, they are currently in the process of implementing a new regional reliability planning and compliance program, the first of its kind in the West.[62] This is illustrated in Figure 52 below.

Figure 52. Types of Capacity Markets

Capacity Market Type	Used In...
Centralized	• PJM Interconnection (**PJM**) • ISO-New England (**ISO-NE**) • New York ISO (**NYISO**) • Midcontinent ISO (**MISO**) • Hybrid (self-supply + residual centralized auction)
Bilateral	• California ISO (**CAISO**) • Southwest Power Pool (**SPP**)



Source: The Sustainable FERC Project

Across the two market types, only centralized markets produce transparent single clearing prices. Historically, prices have oscillated between $1-6/kW-month in these centralized markets, with exceptions occurring in a few select years, notably ISONE in 2018-2019 and MISO in 2022-2023. Price increases in both cases were caused by system tightness, although many attribute the significant percentage increase in MISO to the presence of a "vertical" demand curve that did not signal to the market in prior years that supply was getting tighter.[63] NYISO is the only market with differing seasonal auction prices, with higher prices occurring in summer than winter. These historical price trends are illustrated in Figure 53.

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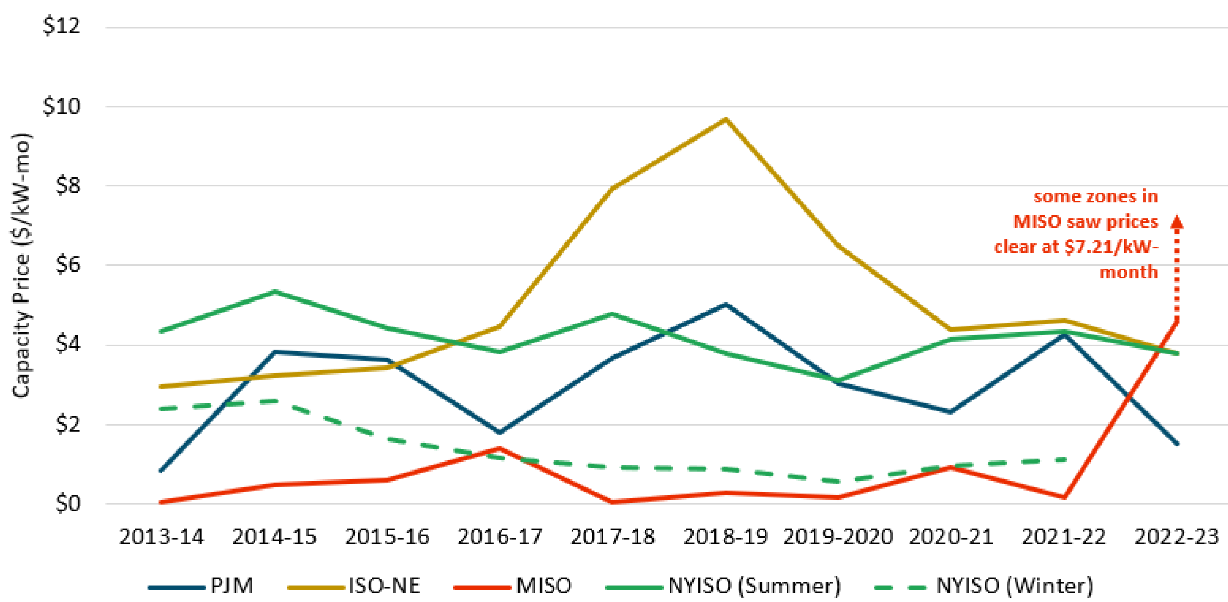
[62] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

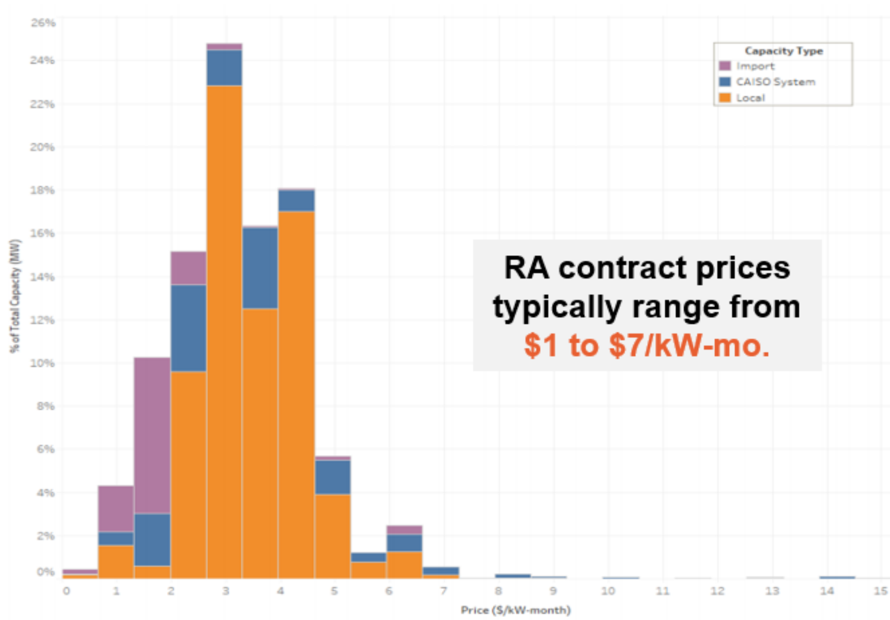
[63] For example, see page vii https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Figure 53. Historical Centralized Market Capacity Prices



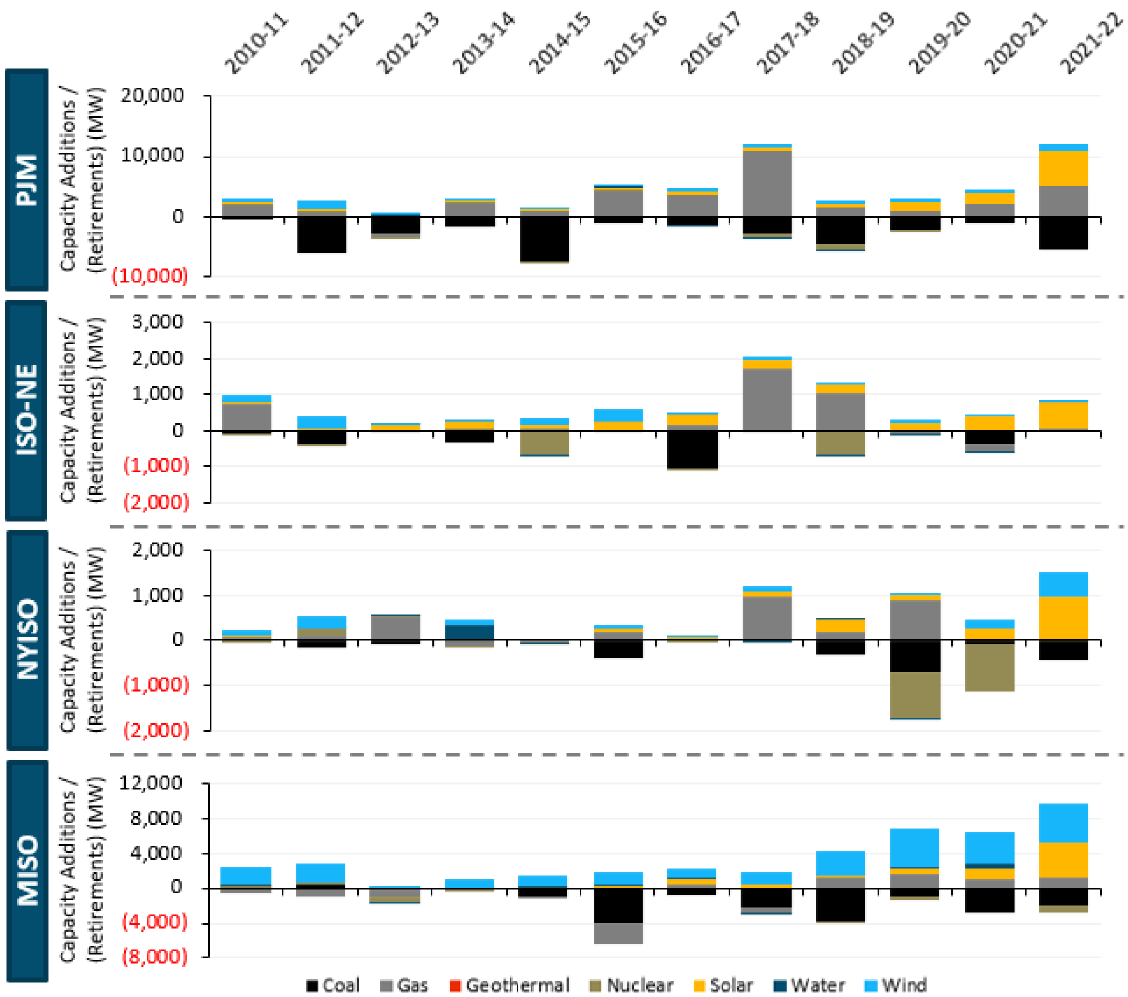
Bilateral markets do not produce centralized prices but are rather comprised of many individual agreements between LSEs and generators. Individual contract prices in these cases can vary for many reasons including location, technology, contract vintage, and contract term (e.g., 3-month capacity strip vs. 2–5-year hedge vs. 10-year tolling agreement for new resources, etc.). The California Public Utilities Commission (CPUC) gathers information of self-reported resource adequacy contract prices and publishes these values into a publicly-available report as illustrated in Figure 54. In general, resource adequacy contract prices vary from $1-7/kW-month.

Figure 54. Historical Bilateral Resource Adequacy Contract Prices



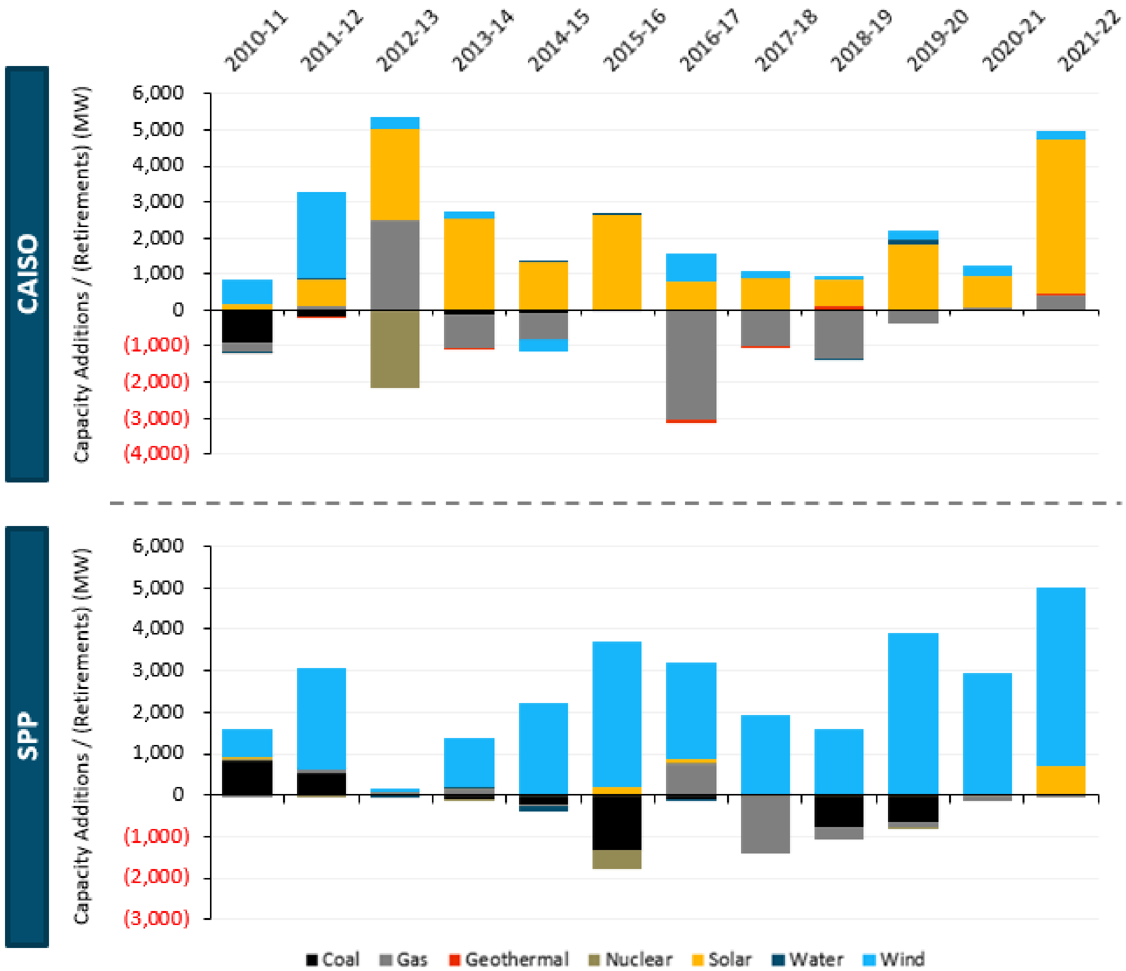
Over the last ten years, the resource mix within ISOs/RTOs with a centralized capacity market framework has changed significantly, primarily the retirement of coal and nuclear plants and the addition of wind, solar, and natural gas resources. While it is not possible to attribute the addition (or retirement) of any individual resource to a single factor, capacity markets and the price signals the provide have been important factors to these investment decisions. Figure 55 provides a summary of portfolio changes over the past ten years in centralized capacity market jurisdictions.

Figure 55. Historical Net Capacity Additions and Retirements in Centralized Markets



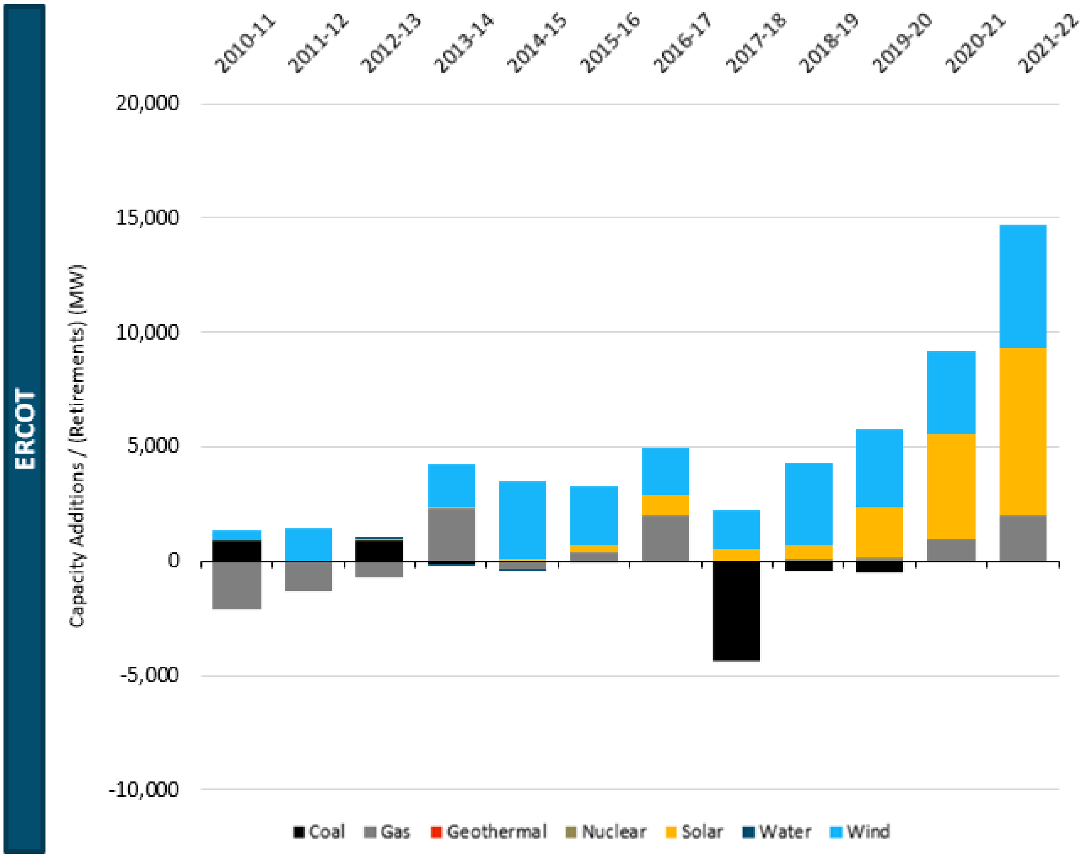
On the other hand, bilateral markets have seen much fewer additions of natural gas, with most new capacity additions concentrated in wind and solar. This result is partially driven by local preferences against natural gas generation in California and a general excess of capacity in SPP as opposed to results driven the differences in the market designs themselves. Figure 56 illustrates these capacity changes.

Figure 56. Historical Net Capacity Additions and Retirements in Bilateral Markets



The ERCOT market stands alone as the only U.S. restructured electricity market without a reliability mechanism. Under this market design, ERCOT has seen a significant increases in wind and more recently solar. The system has added new natural gas capacity as well, although the magnitude of these additions has been offset by coal retirements. Figure 57 demonstrates ERCOT capacity additions and retirements over the past decade.

Figure 57. Historical Net Capacity Additions and Retirements in ERCOT (MW)



The detailed data used to build Figure 55, Figure 56, and Figure 57 can be found in Table 60 below.

Table 60. Historical Net Capacity Additions and Retirements Across Regions (MW)

ERCOT

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	895	(19)	914	(110)	(16)	(4)	0	(4,357)	(403)	(472)	0	0	0
Gas	(2,137)	(1,269)	(690)	2,318	(353)	408	2,022	(55)	92	103	1,012	2,005	1,158
Nuclear	12	0	0	0	0	0	0	0	0	100	0	0	0
Solar	30	32	51	66	118	266	863	511	599	2,174	4,554	7,323	27,871
Hydro	0	0	1	(17)	(1)	0	0	0	0	4	0	0	0
Wind	380	1,362	0	1,836	3,367	2,618	2,076	1,706	3,603	3,403	3,592	5,379	4,620

PJM

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	(427)	(5,923)	(2,810)	(1,498)	(7,458)	(1,170)	(1,468)	(2,734)	(4,520)	(2,217)	(1,030)	(5,402)	(2,332)
Gas	1,751	781	(605)	2,162	889	4,126	3,544	10,814	1,641	1,124	2,197	5,173	3,426
Nuclear	428	239	(189)	321	(17)	227	0	(576)	(975)	(10)	0	0	0
Solar	242	198	152	185	386	550	536	555	598	1,287	1,649	5,612	9,680
Hydro	116	22	149	65	5	167	(17)	(0)	(31)	0	3	4	5
Wind	626	1,577	8	239	353	428	777	710	515	550	624	1,215	865

MISO

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	83	395	(209)	(110)	(892)	(4,053)	(721)	(2,192)	(3,813)	(974)	(2,697)	(1,970)	(2,125)
Gas	(565)	(916)	(820)	(3)	(315)	(2,260)	457	(625)	1,147	1,694	972	1,217	815
Nuclear	175	128	(519)	(22)	41	12	0	(3)	(6)	(498)	0	(816)	0
Solar	5	12	47	46	50	217	527	374	236	621	1,168	4,026	9,675
Hydro	71	145	(8)	14	60	146	143	(0)	71	110	730	0	10
Wind	2,142	2,133	210	1,003	1,295	1,356	1,106	1,500	2,810	4,381	3,498	4,424	3,189

SPP

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	844	549	(28)	(82)	(215)	(1,325)	(89)	(27)	(781)	(659)	0	0	0
Gas	(56)	57	78	140	(64)	(0)	751	(1,371)	(295)	(94)	(142)	(51)	175
Nuclear	21	(25)	1	(2)	(1)	(471)	49	0	0	(62)	0	0	0
Solar	53	0	1	7	6	213	59	25	26	36	15	702	1,451
Water	4	2	(3)	46	(127)	0	(2)	4	1	7	0	0	5
Wind	665	2,463	81	1,171	2,199	3,504	2,323	1,897	1,565	3,856	2,915	4,291	3,111

NYISO

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	(5)	(140)	(67)	(5)	4	(386)	7	3	(320)	(684)	(75)	(445)	0
Gas	72	108	530	(96)	(30)	205	12	959	212	879	(2)	3	33
Nuclear	(17)	164	0	(1)	(3)	2	(15)	(1)	1	(1,018)	(1,039)	0	0
Solar	36	15	5	14	35	63	62	148	244	149	256	965	4,033
Hydro	11	2	8	330	(1)	1	8	(12)	2	(4)	0	0	0
Wind	126	238	0	111	0	78	2	79	0	0	220	549	1,252

ISO-NE

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	(102)	(359)	(4)	(346)	0	(27)	(1,056)	0	0	(3)	(383)	0	0
Gas	758	(30)	(4)	4	83	34	157	1,721	1,039	(79)	(209)	75	143
Nuclear	(1)	(25)	11	39	(665)	0	(2)	(1)	(685)	0	0	0	0
Solar	14	62	141	201	87	205	309	235	247	227	419	704	847
Hydro	37	22	2	18	(1)	26	1	(2)	(3)	(9)	(4)	5	0
Wind	195	316	3	12	193	338	48	101	41	73	34	20	188

CAISO

Resource Type	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Coal	(891)	(173)	0	(133)	(63)	0	0	0	3	0	0	0	0
Gas	(236)	125	2,504	(892)	(737)	13	(3,034)	(980)	(1,316)	(373)	52	403	(2,219)
Nuclear	(38)	(15)	(7)	(77)	(25)	(1)	(113)	(77)	131	25	0	30	30
Geothermal	(1)	0	(2,150)	11	0	0	0	0	0	0	0	0	0
Solar	189	725	2,500	2,526	1,341	2,614	795	913	716	1,788	877	4,291	5,302
Hydro	(39)	38	34	2	9	12	0	3	(74)	151	0	1	(3)
Wind	675	2,403	329	190	(299)	(36)	756	169	116	257	307	251	418