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

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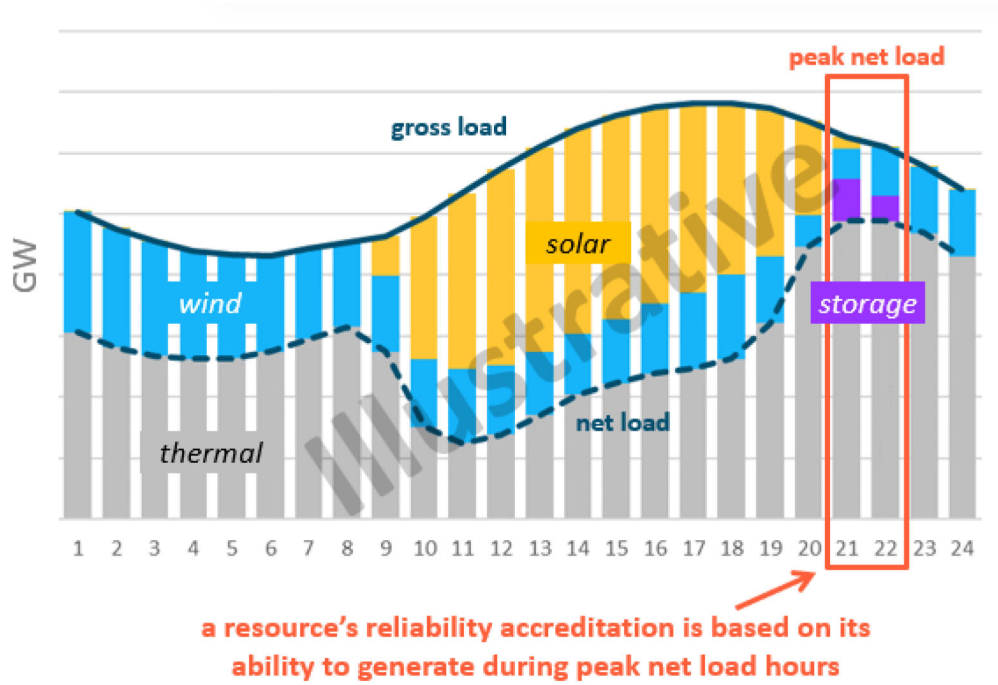
[52] https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf.
[53] https://www.iso-ne.com/static-assets/documents/2022/10/a09e_mc_2022_10_12-13_rca_iso_scope_memo.pdf.
[54] For example, see page 5 https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

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

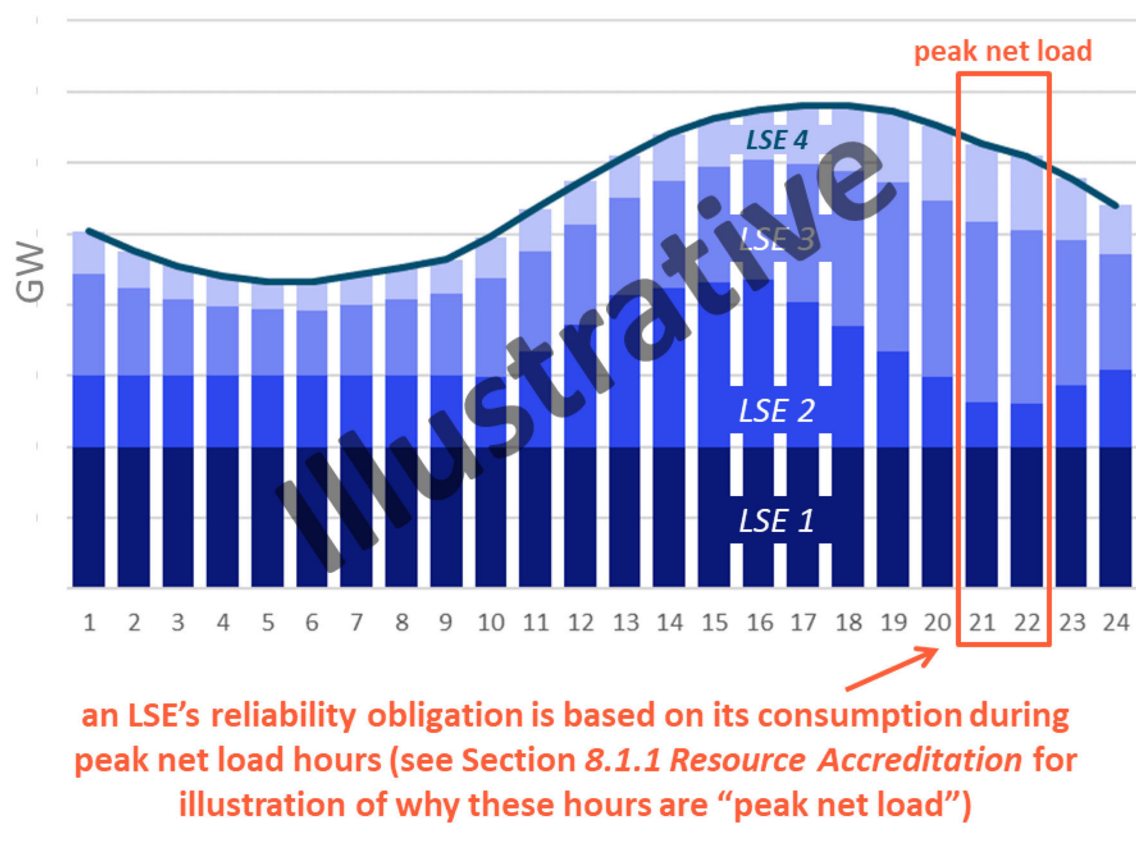
All U.S. markets with a reliability mechanism use a centralized accreditation process so this has the benefit of being a tested and proven feature. Additionally, centralized accreditation gives ERCOT and the PUCT strong confidence that there are sufficient resources to meet reliability requirements without 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

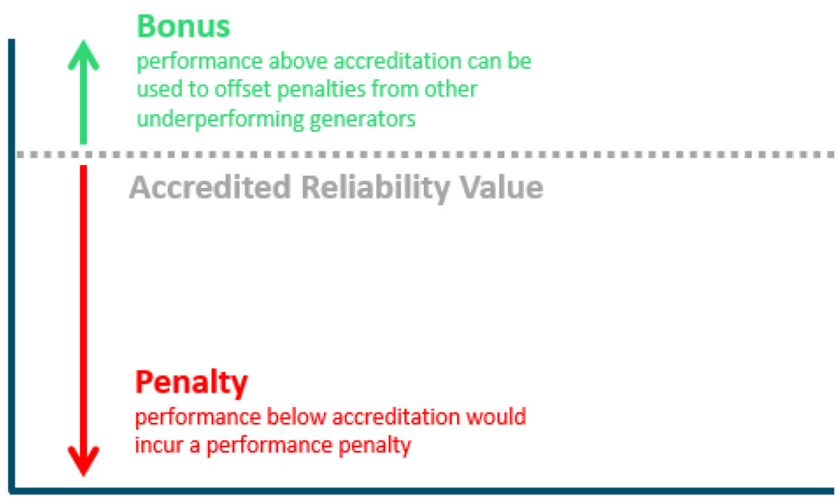
Assessment Hours	Underperformance Penalty
+ **Should be focused on the hours of highest reliability risk each year, consistent with the hours used to accredit resources** • ~30 hours/year strikes a balance between actual expected loss of load hours (~3 hr./year) and including too many hours which are 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]

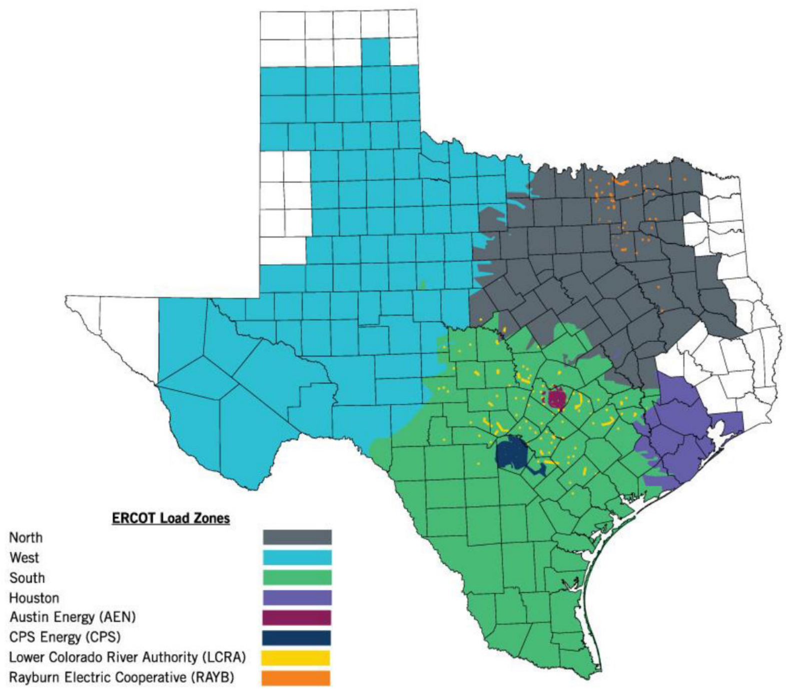
8.1.5 Zonal/Geographic Construct

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

[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/.

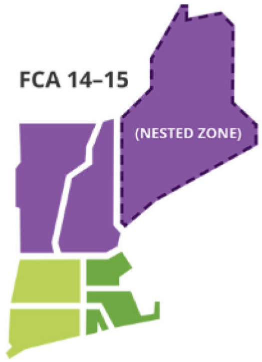
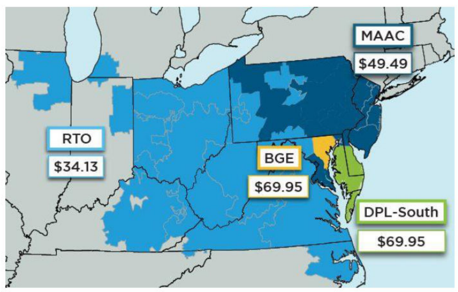
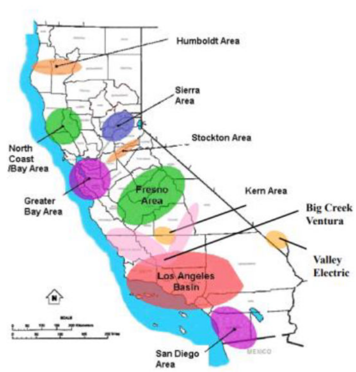
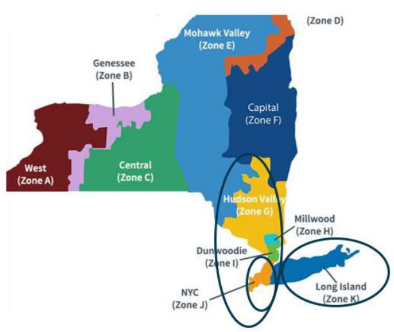
that reliability resources locate in geographies where they are needed near loads (as opposed to areas where there is not sufficient transmission capability to deliver these resources), ERCOT would need to set zonal reliability requirements. This study analyzes the ERCOT system as a "copper sheet" without 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

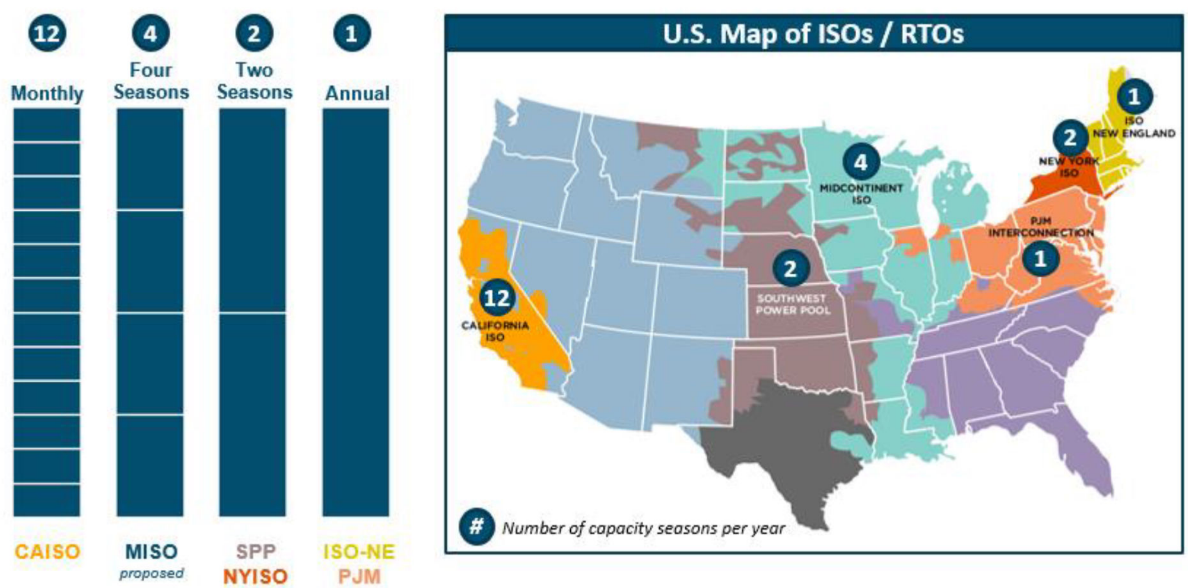
Zone	Map	Recent Market Prices *($/kW-month)*	Description
ISO-NE		NNE: $2.53 SENE: $2.64 Rest of Pool: $2.59	ISO-NE establishes capacity zones on an annual basis which results in different capacity zones in each auction
PJM		System: $1.04 Highest Zonal Price: $2.13 (DPL-South & BGE)	Import limitations 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.

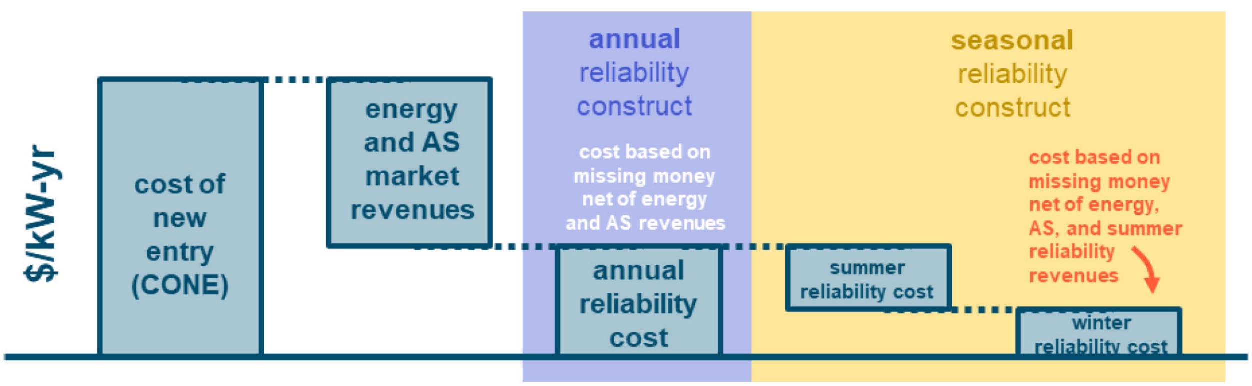
Table 51 below demonstrates how a seasonal LSERO and FRM approach might differ from an annual reliability approach and which components are affected.

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:** ***Supplier*** reconfiguration auction #1 (allows for generators to change their commitment) + **1-Mo Forward:** ***Supplier*** 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 *bilateral* procurement framework (LSERO)	Options under *centralized* 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

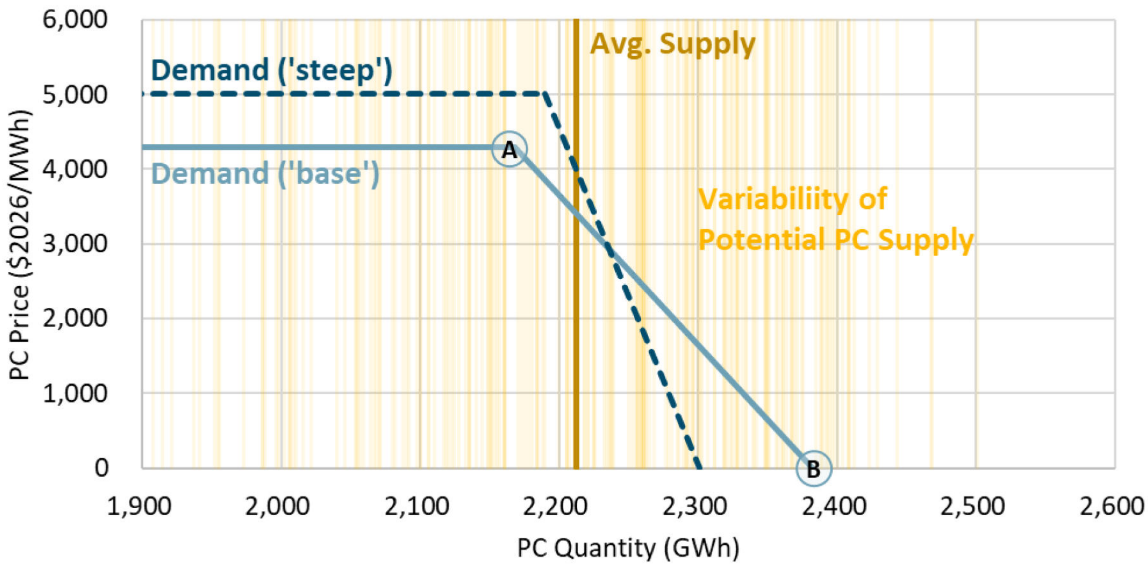
8.2.1 Demand Curve Determination

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.

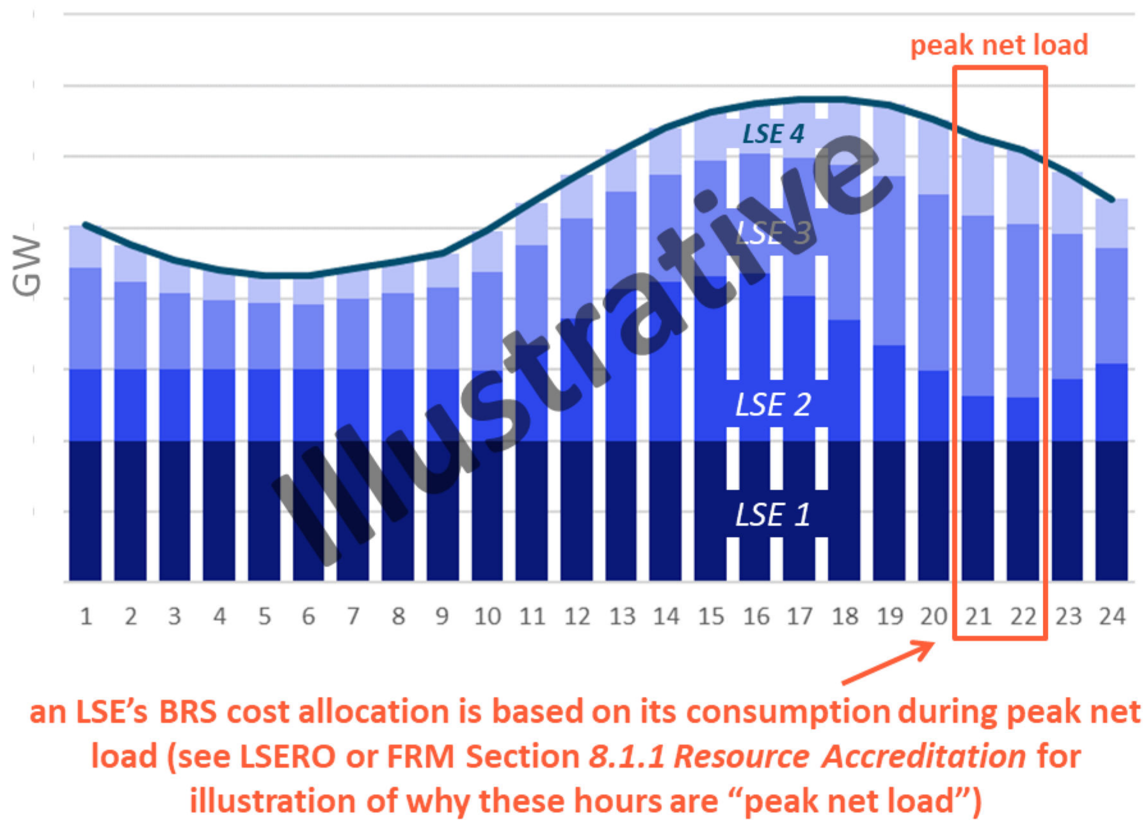
Table 54. Pros and Cons of Procurement Mechanism Options

	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.

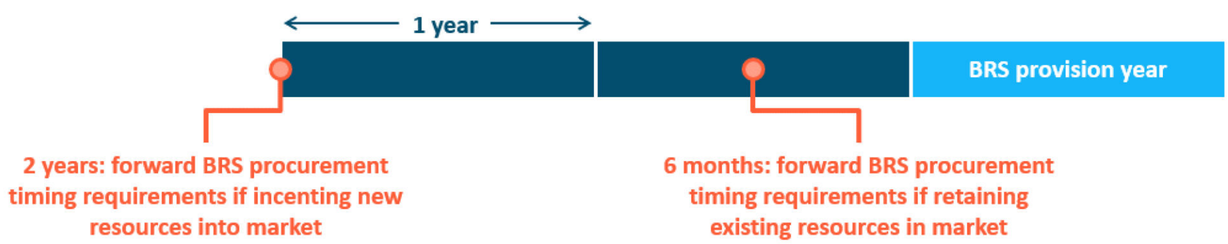
The penalty for underperformance should be stringent enough to incentivize proper investment and maintenance in the facility but not too high as to impose undue risk and prevent resources from participating in the BRS market and claw back part or all of the BRS payment. A standard basis that balances 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

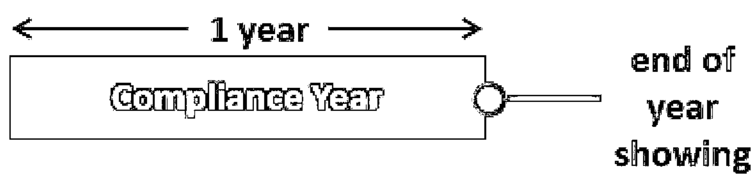
This study assumes the DEC procurement mechanism leverages the existing renewable energy credit (REC) procurement mechanisms, relying on bilateral contracting between individual LSEs and generators with a centralized entity in charge of tracking. In a DEC construct, ERCOT or another delegated agency 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

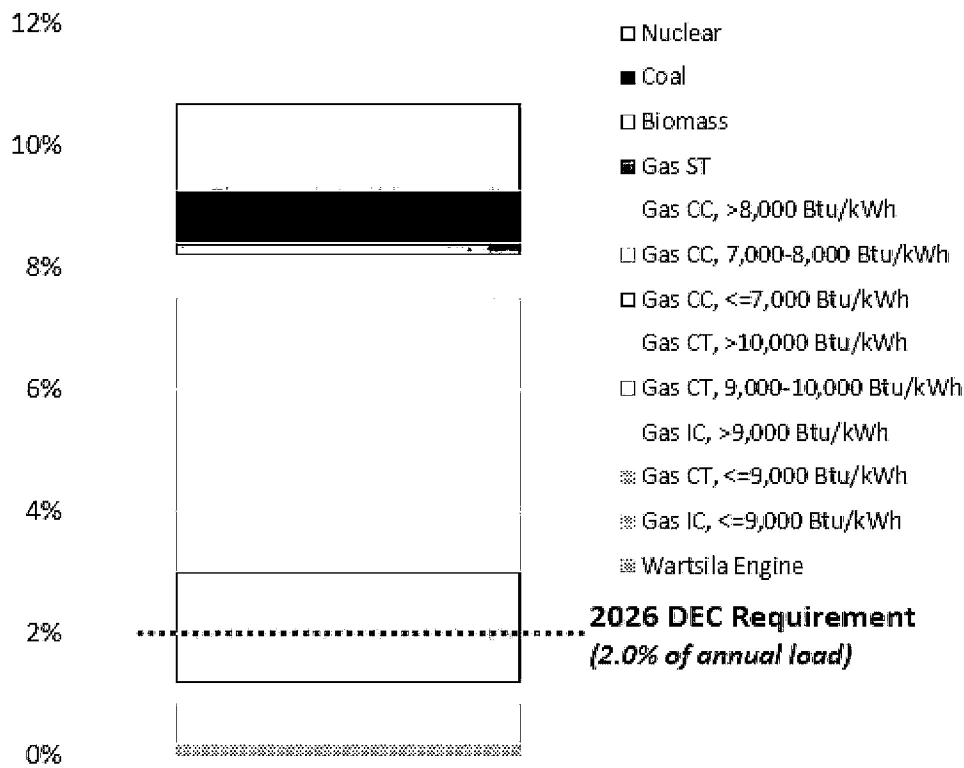
This DEC framework in this study is designed to reward resources for "dispatchability", defined as the ability to dispatch at the direction of the system operator. Defining dispatchability is an often ambiguous and debated topic within the electricity industry and inherently involves setting administrative 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.

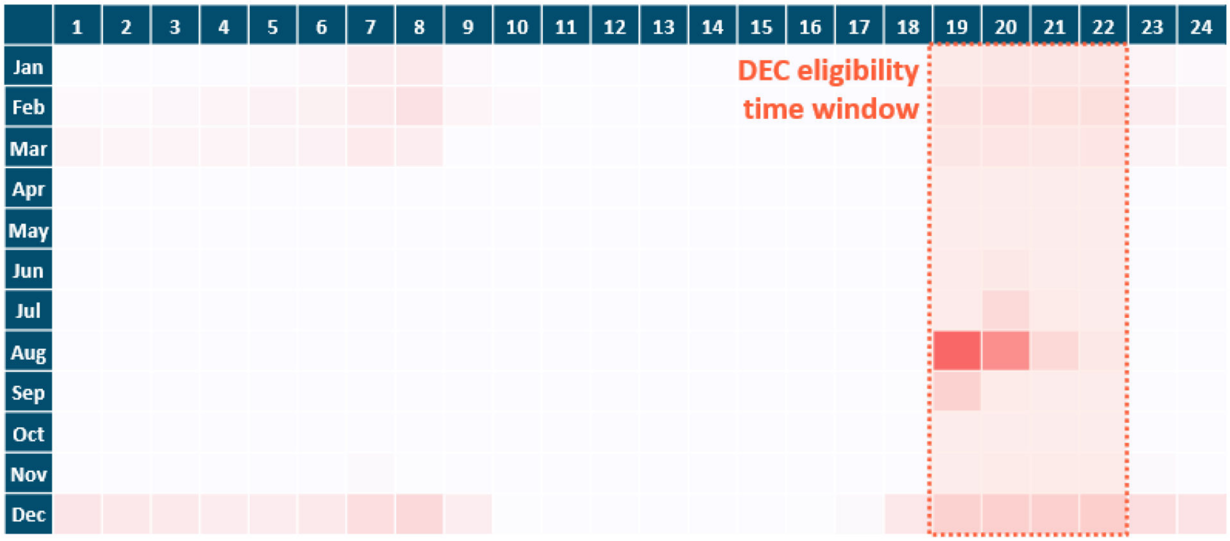
Figure 47. Potential DEC Generation by Resource Type (% of 2026 Annual Load)



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.

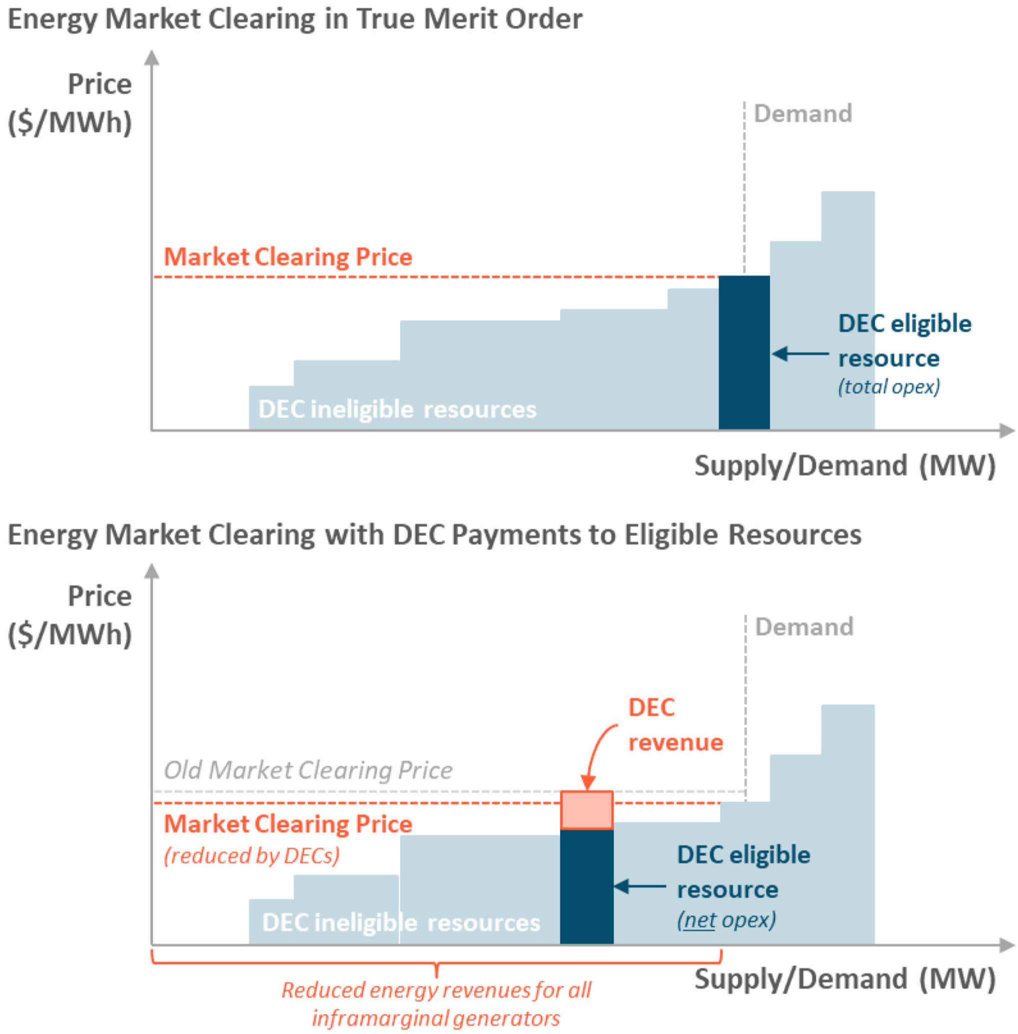
8.4.7 LSE Compliance Penalties

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)

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

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.

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[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.

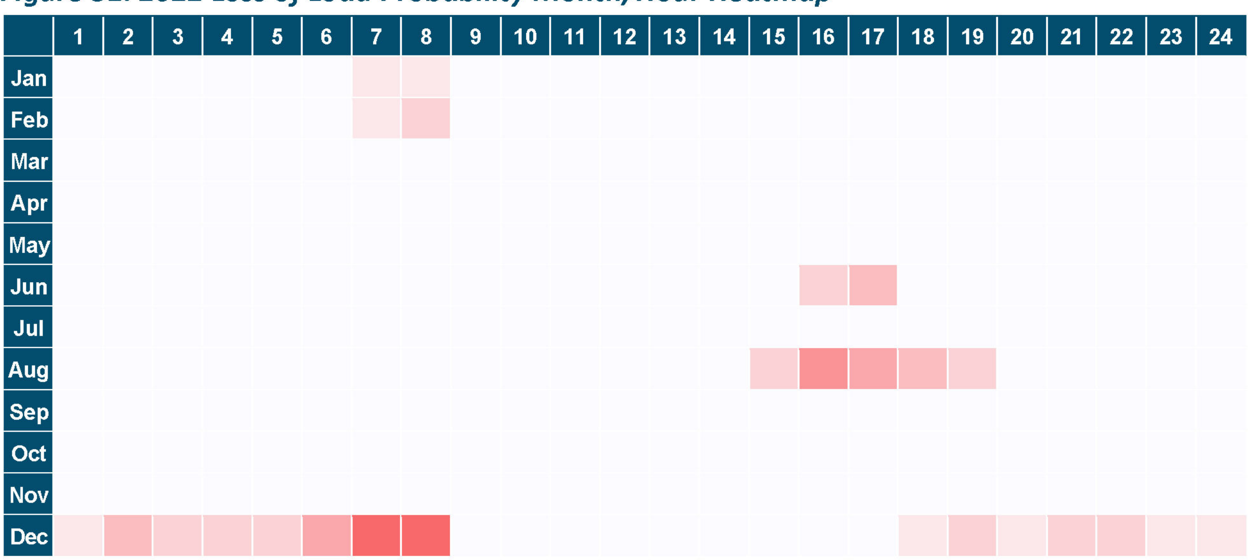
Table 58. 2022 Reliability Statistics

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

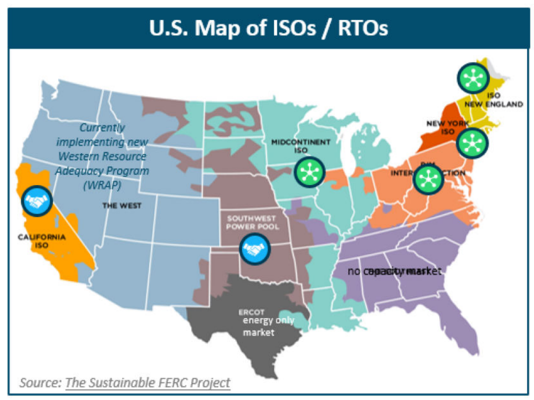
	Loss of Load Hours per Year (hours/year)			
	0	**1**	**2**	**3+**
Probability	97.5%	1.0%	1.0%	0.5%

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**)



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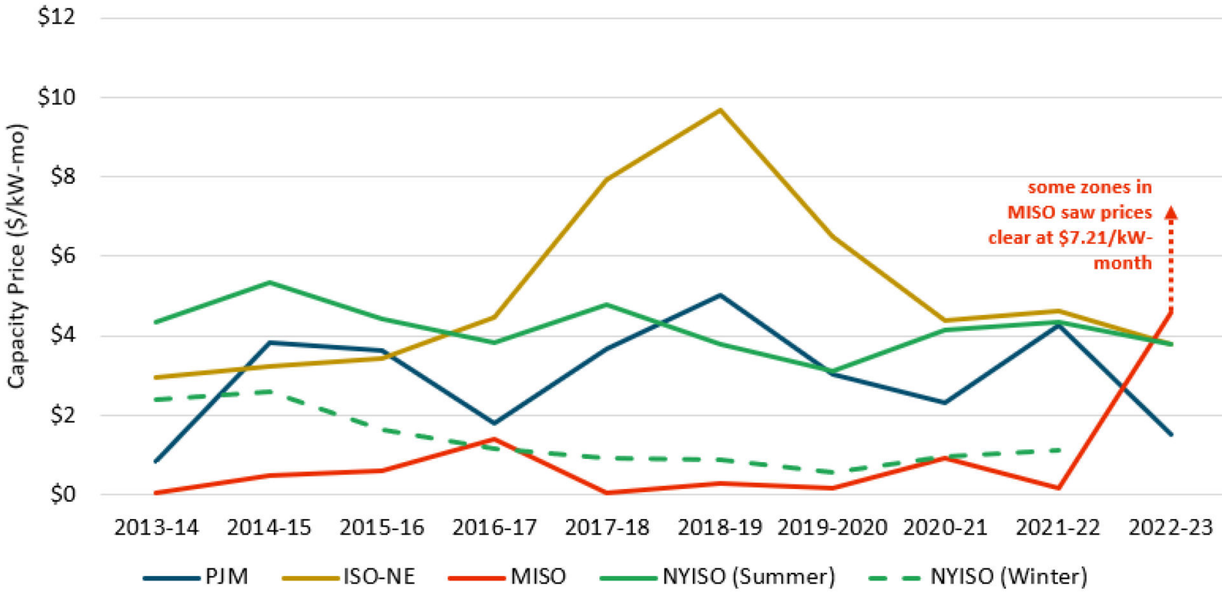
[62] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

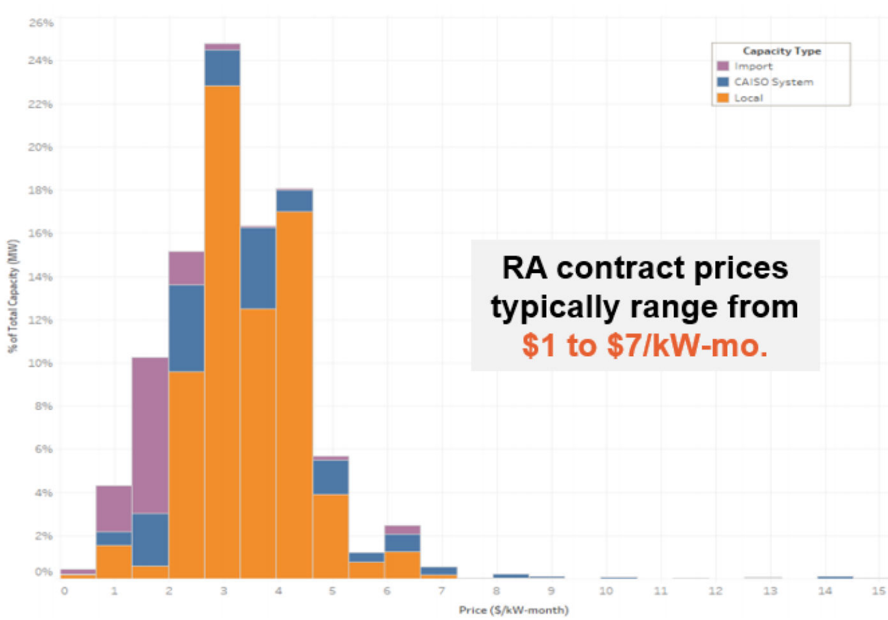
[63] For example, see page vii https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Figure 53. Historical Centralized Market Capacity Prices



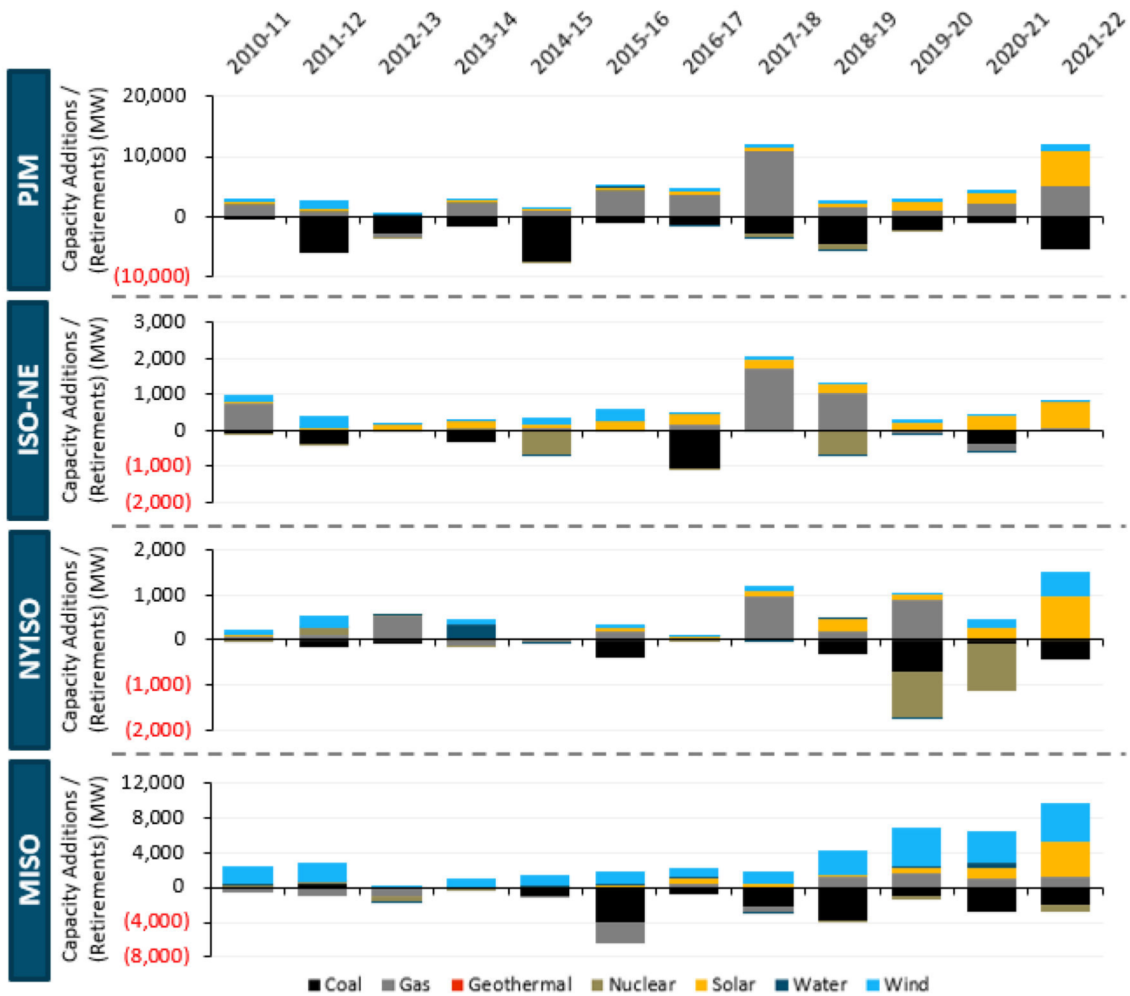
Bilateral markets do not produce centralized prices but are rather comprised of many individual agreements between LSEs and generators. Individual contract prices in these cases can vary for many reasons including location, technology, contract vintage, and contract term (e.g., 3-month capacity strip 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



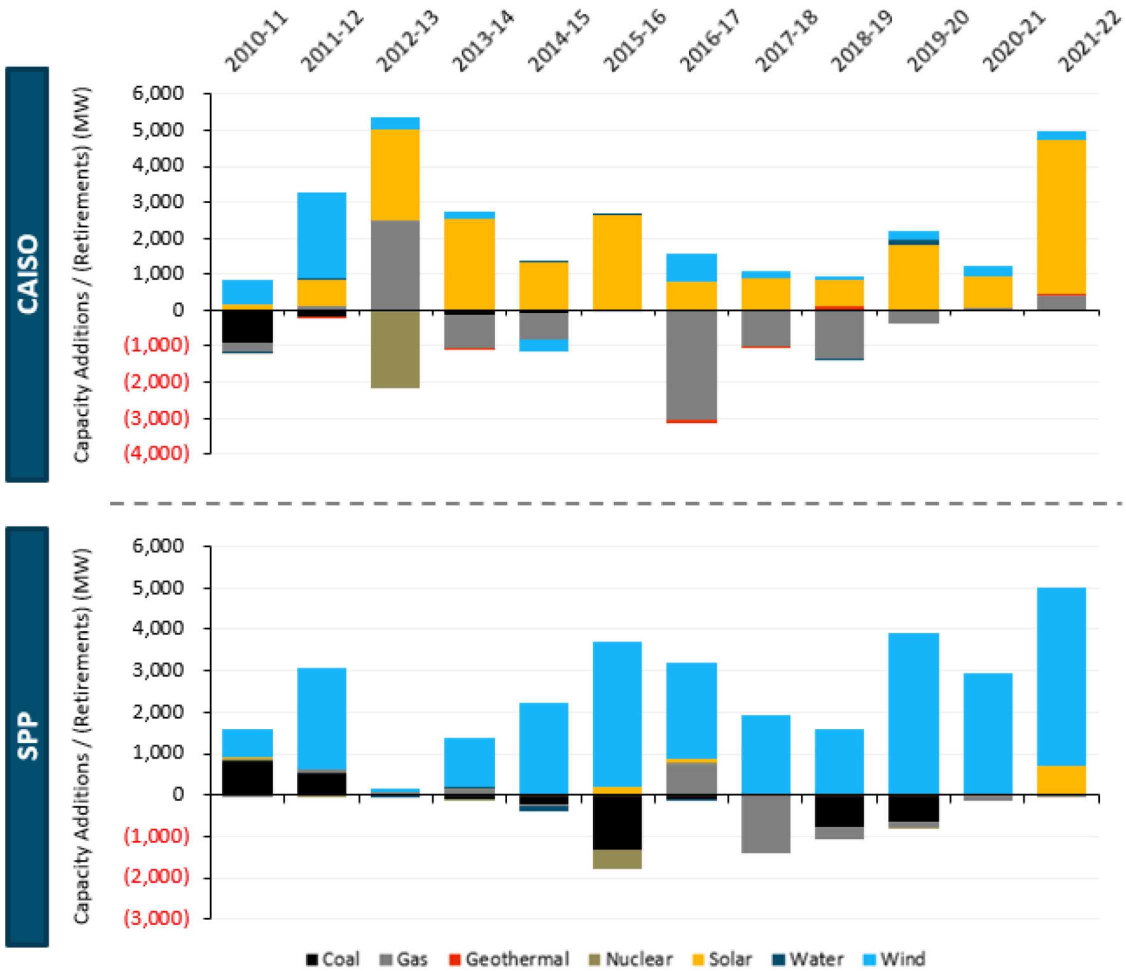
Over the last ten years, the resource mix within ISOs/RTOs with a centralized capacity market framework has changed significantly, primarily the retirement of coal and nuclear plants and the addition of wind, solar, and natural gas resources. While it is not possible to attribute the addition (or retirement) 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



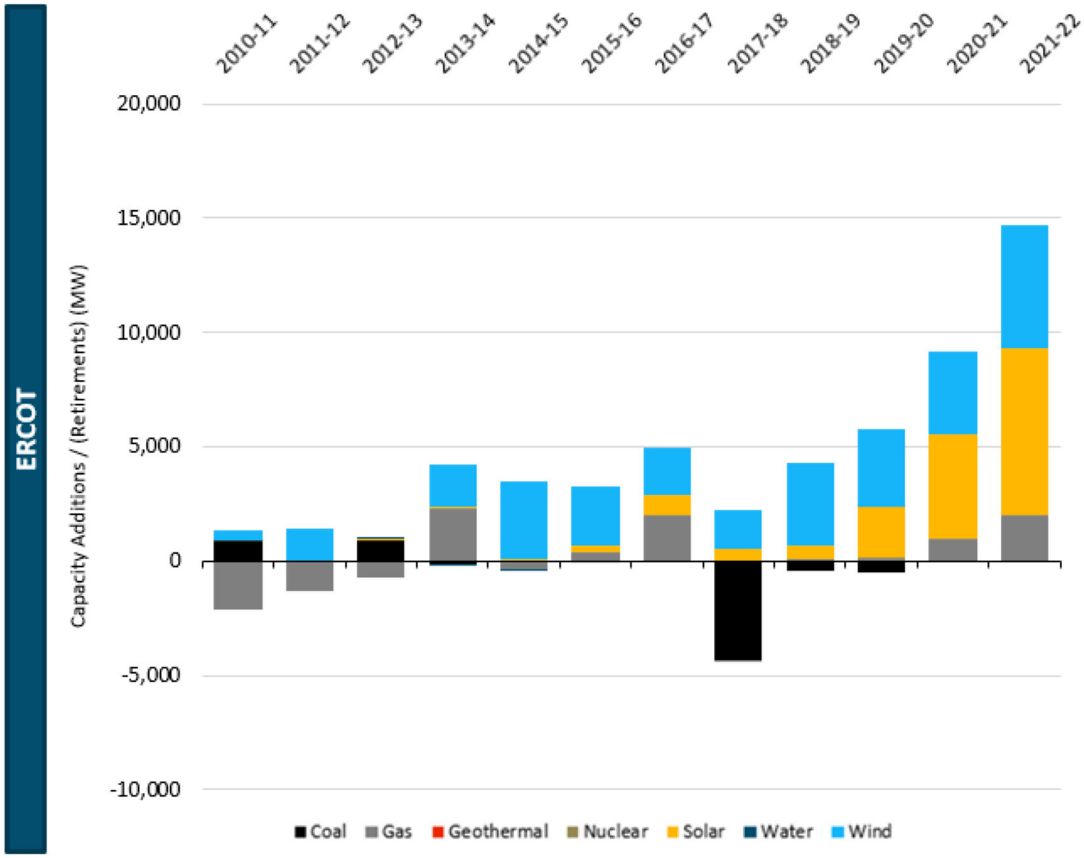
On the other hand, bilateral markets have seen much fewer additions of natural gas, with most new capacity additions concentrated in wind and solar. This result is partially driven by local preferences against natural gas generation in California and a general excess of capacity in SPP as opposed to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