Assessment of ERCOT Market Structural Changes

October 26, 2022

Submitted to:
Consumer Fund of Texas

Submitted by:
ICF Resources, LLC

IMPORTANT NOTICE:

REVIEW OR USE OF THIS REPORT BY ANY PARTY OTHER THAN THE CLIENT CONSTITUTES ACCEPTANCE OF THE FOLLOWING TERMS. Read these terms carefully.

They constitute a binding agreement between you and ICF Resources, LLC ("ICF"). By your review or use of the report, you hereby agree to the following terms.

Any use of this report other than as a whole and in conjunction with this disclaimer is forbidden.

This report and information and statements herein are based in whole or in part on information obtained from various sources. ICF makes no assurances as to the accuracy of any such information or any conclusions based thereon. ICF is not responsible for typographical, pictorial, or other editorial errors. The report is provided **AS IS.**

NO WARRANTY, WHETHER EXPRESS OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE IS GIVEN OR MADE BY ICF IN CONNECTION WITH THIS REPORT.

You use this report at your own risk. ICF is not liable for any damages of any kind attributable to your use of this report.

Contact Information

9300 Lee Highway
Fairfax, Virginia 22031

Pat Milligan
Senior Manager
703-225-5856
Pat.Milligan@icf.com

Dinesh Madan
Technical Director
703-713-8846
Dinesh.Madan@icf.com

Ayush Goel
Consultant
Ayush.Goel@icf.com

Contents

1 Introduction

The purpose of this analysis is to estimate the cost and reliability impacts of recent and proposed changes to the ERCOT wholesale electricity market in Texas. ICF Resources LLC ("ICF") was engaged for this purpose by the Consumer Fund of Texas (the "Client"). A complementary report, to be released in November 2022, will assess the cost and reliability impacts of using high levels of demand-side resources to improve reliability in ERCOT, and will compare those impacts to the supply-side changes assessed in this study.

ICF's analysis is based on production cost modeling using ABB's PROMOD IV®, ICF-proprietary Monte Carlo stochastic modeling for loss-of-load probabilities ("SRAM"), further ICF modeling related to new market products based on their proposed rules (insofar as information could be found publicly), public and proprietary data sources, and ICF's broad experience modeling U.S. organized power markets. The Appendix describes the suite of ICF models and the principal assumptions and data sources used in this analysis.

The recent and proposed market changes within ERCOT can be assessed by comparing their impacts across three different time periods – the market rules that existed before, during, and just after Winter Storm Uri in 2021 (Phase 0), the operational and policy changes implemented by ERCOT and the Public Utility Commission of Texas (PUCT) between Summer 2021 and the present (Phase 1), and the additional policy options now under consideration by the PUCT (Phase 2) for implementation in 2023 and beyond. This analysis looks at the reliability and cost impacts of these various policies in the years 2023, 2024, 2025, 2027 and 2030, testing each against an identical set of future normal and extreme weather, demand and power plant outage conditions that could stress the ERCOT grid. The numbers reported below represent averages of the reliability and cost results for 1,000 combinations of future weather, demand and other conditions used to test how each of the policy scenarios would perform over time.

Phase 1 measures include changes to the scarcity pricing construct, mandates for winter weatherization of power plants, increased budgets for Emergency Response Service ("ERS", compensated industrial demand response), and increased ancillary service procurements among other changes. The Phase 2 policy options are assumed to be implemented on top of the existing Phase 1 measures. Phase 2 policies considered include the Backstop Reliability Service ("BRS"[1]), the Load-Serving Entity Obligation ("LSEO"[2]), and Dispatchable Energy Credits ("DEC"[3]).

[1] ICF's framing of the BRS policy will pay coal and natural gas generators that would have retired to instead remain available for emergency operation.

[2] Designed to provide extra compensation to generators based on their ability to serve peak demand

[3] A construct intended to reward fast, flexible resources to serve daily grid operational needs

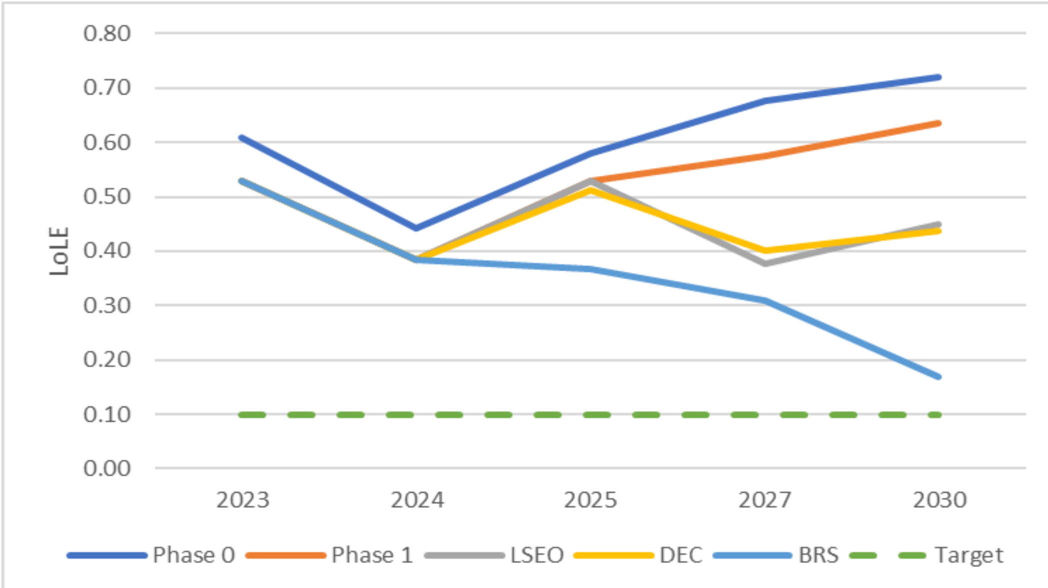
2 Executive Summary

A detailed analysis of the costs and reliability impacts of current and proposed changes to the ERCOT market produced the following findings:

- Currently, Texans should expect, on average, approximately **five outages every ten years**, or a 0.5 Loss of Load Expectation (LoLE). Reliability is forecasted to further deteriorate by 2030 if no further policy measures are taken.
- None of the current proposals, by themselves, would improve reliability enough to yield one outage every ten years (0.1 LoLE, a generally accepted industry standard) but the Backstop Reliability Service (BRS) shows the greatest reliability improvements, yielding less than two outages per decade by 2030 (0.17 LoLE).
- Both the Load Serving Entity Obligation (LSEO) and the Dispatchable Energy Credit (DEC) proposals would improve reliability compared to Phase 0 but still result in between 4-5 outages per decade. However, the two programs have very different costs:
  - The LSEO would likely cost consumers \$8.5 billion in the year 2025 alone, and \$22.5 billion from 2025-2030 in total. We forecast LSEO to bring online 2.5 GW of additional gas generation by 2030 compared to Phase 1.
  - The DEC proposal would cost consumers \$1.3b total over the first three years (2023-2025), but then actually reduce the total costs to consumers by approximately \$2b each year from 2027-2030. We forecast DEC to bring online 3.4 GW of additional 2-hour battery storage by 2030 compared to Phase 1.
  - The BRS would cost \$838 million in its highest year (2030) and a total of \$2.6 billion from 2025-2030, 90% less than the LSEO with far greater reliability benefits. We forecast BRS to preserve 8.0 GW of capacity that would otherwise retire by 2030 under Phase 1.
- **There are downsides and challenges to all three Phase 2 proposals, and yet significant risks of prolonged and numerous outages if no action is taken.**

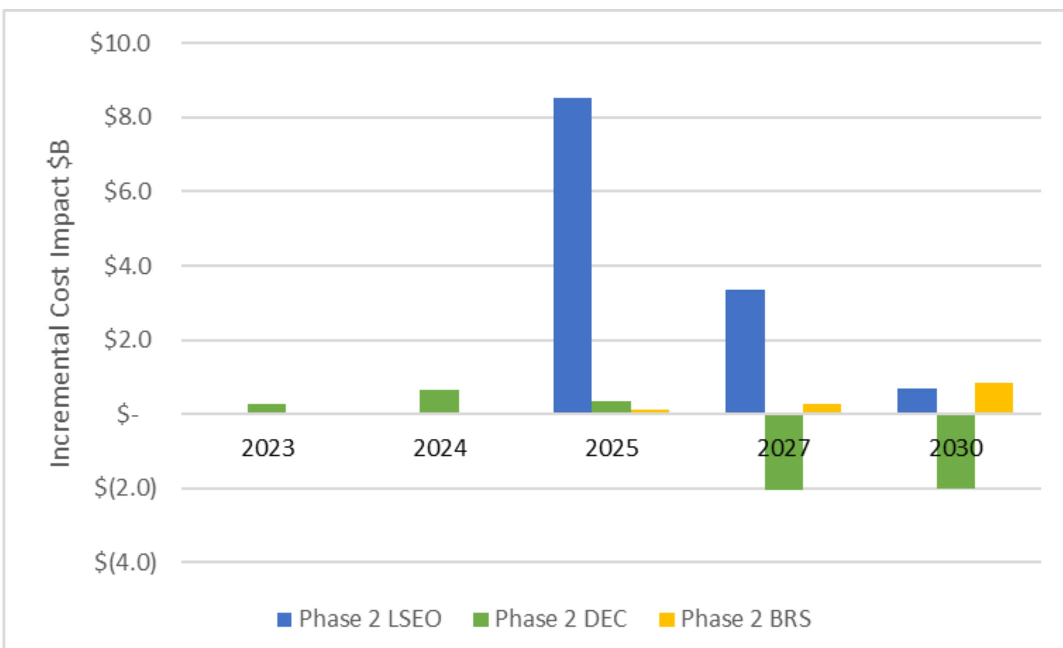
Figure ES-1 shows that while none of the Phase 1 and Phase 2 options achieve the target reliability level of one outage in ten years, the Phase 2-BRS option achieves better reliability faster than any of the other measures.

Figure ES-1: All ERCOT market scenarios will produce worse Loss-of-Load Expectation (LoLE) than target



The annual cost impacts of the Phase 2 policy options, measured as increments over Phase 1 costs, are shown below in Figure ES-2.

Figure ES-2: Incremental cost impact over Phase 1 is highest for LSEO and negative for DEC



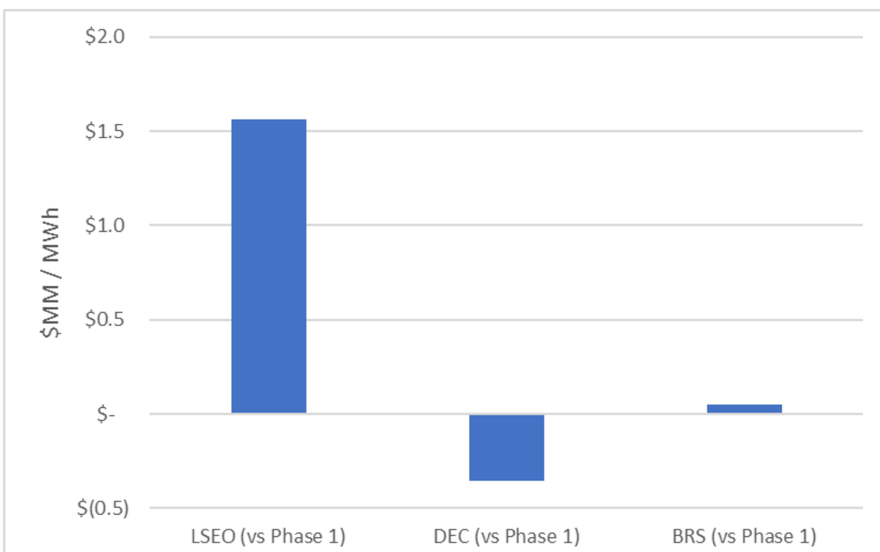
The first year of the LSEO implementation (modeled as 2025) is forecasted to raise wholesale electric prices by $8.5 billion (an increase of 35% over the costs of the Phase 1 market). LSEO costs could lower and stabilize in later years, but the forward payments to generators that begin in 2025 will not yield any additional new gas plants until the 2026-2027 timeframe and would not keep old gas or coal plants from retiring. **The LSEO proposal offers the highest forecasted cost impact while delivering the least reliability improvements.**

The DEC program would add a new payment stream to a limited subset of resources – specifically, fast and flexible resources needed to stabilize supply particularly during solar and wind ramps and sudden generation or transmission losses. Unlike the BRS, units receiving DEC payments do participate in the wholesale market and affect market prices. Because the DEC incentives are forecasted to bring new storage and fast-responding generation capacity online, market prices will drop (especially scarcity prices) over time. **On net, the DEC program therefore has negative total costs (i.e., it will deliver cost savings for consumers).**

The BRS program has modest costs, on average increasing total market costs by about 2% over 2025-2030 (about $2.6 billion or 90% less than the LSEO). **BRS costs are much smaller than the LSEO because the BRS is not a market-wide mechanism and targets payments to a limited subset of capacity**, that is, resources that would otherwise retire but are instead kept operational and deployed only during emergency conditions.

Figure ES-3 shows the total cost of each Phase 2 policy option compared to the amount of reliability improvement achieved (as measured by MWh of lost load reduction) against Phase 1 over 2023-2030. The LSEO is the least cost-effective, while BRS is very cost-effective. Wholesale costs are net negative under the DEC while improving reliability. Correspondingly, generators' aggregate earnings increase significantly under the LSEO, decrease under the DEC, and are unchanged under the BRS compared to Phase 1.

Figure ES-3: Cost per added MW of generation is highest for LSEO and low for DEC and BRS



ICF makes the following comments and observations with respect to each policy option:

Phase 1

- **Despite winter weatherization mandates, the biggest threat to reliability in ERCOT continues to be in winter months**. Summer and winter reliability must be dealt with differently. Renewable output and thermal generation are more uncertain in winter, and demand uncertainty is higher.

- It is ICF's strong opinion that the methodology ERCOT uses to measure reserve margin in the biannual Capacity, Demand, and Reserves Report (CDR) is poor and creates the false perception that grid reliability is high and fast improving. While Phase 1 results in reliability improvements, reliability is still relatively poor.

Phase 2 LSEO

- The cost and reliability impact of the LSEO depends heavily on technical details that are not specified in the proposal. **This creates a huge range of possible outcomes.**
- The most critical uncertainty is resource accreditation: that is, how much an administrator decides each resource contributes to reliability. Depending on these decisions, the market could be shown to have significant excess capacity (thus costing little but also impacting reliability little) or to be significantly short of capacity.
- If the market is very short of capacity under the LSEO, there is a large risk that costs could be extremely high – **potentially doubling compared to Phase 1** – especially in the first year of implementation (whether 2025, 2026 or later).
- The LSEO would significantly strain the competitive retail market. Other U.S. power markets with a resource adequacy construct (such as MISO, SPP, and CAISO) are dominated by regulated utilities and allow limited or zero retail choice.
- The short-term nature of likely capacity contracts under the LSEO means financing new resources will not be much easier than under Phase 1 unless contract prices are very high, limiting program impact on reliability.

Phase 2 DEC

- **While the LSEO and BRS center on improving resource adequacy, the DEC program centers on improving operational flexibility.** Each program attempts to solve differing challenges for the grid, and therefore are not necessarily mutually-exclusive.
- The DEC has a positive reliability impact primarily through bringing online additional 2-hour batteries. Over the long-term however, the reliability impact of 2-hour batteries declines.
- One concern with DEC is that it creates additional payments for a small subset of (mostly new) resources, which **suppresses market energy prices and could prompt accelerated, additional retirements** (although our study does not forecast this in the Base Case).

Phase 2 BRS

- BRS has a large impact because we forecast it will impact a greater amount of capacity (8.0 GW vs 3.4 GW for DEC and 2.5 GW for LSEO).
- **Cost reimbursement for resources in the BRS program must be done very carefully** to avoid creating perverse economic incentives. Additionally, ERCOT must ensure BRS generators do not impact wholesale market prices in any circumstance.

A future analysis by ICF will look at how energy efficiency, demand response, and other distributed energy resources would impact each of the Phase 2 proposals, as well as current state. These resources may be able to come online sooner and improve reliability in the near-term compared to programs focused on generation.

2 Major Findings

ICF's study evaluated the reliability and cost impacts of Phase 1 and proposed Phase 2 market reforms. ICF evaluated four categories of system wholesale energy costs:

1. Energy costs – These are **marginal** energy prices per kWh (real-time locational marginal prices), differentiated from settlement prices which include scarcity price adders
2. Scarcity costs – These include the real-time online and offline price adders as well as the reliability deployment price adder, all of which are added to per kWh energy costs
3. Ancillary costs – Sum of Responsive Reserve Service (RRS), Regulation Up and Down, Non-Spin, and the new ERCOT Contingency Reserve Service (ECRS) product considered in Phase 1 and all Phase 2 scenarios
4. Program costs – Additional costs from Phase 2 programs (and higher ERS budgets in Phase 1)

Costs to consumers are not exclusively based on ERCOT spot prices. Contracting between financial entities, load-serving entities (LSEs), generators, and other hedging can reduce or increase costs depending on customer class, etc. However, all contracts are ultimately marked to market based on spot prices, and over the long-term ERCOT energy contract prices should converge towards ERCOT spot market prices. For simplicity of analysis, this analysis uses "wholesale market costs" to mean the sum of hourly prices times system load, which represents unhedged costs relative to what individual market participants may actually pay. This analysis does not address transmission and distribution costs, ERCOT usage fees, retailer margins, Winter Storm Uri loss recovery charges, and other factors added into retail customer electricity costs because the Phase 1 and 2 reforms change wholesale market energy costs but have minor effects on other retail cost elements.

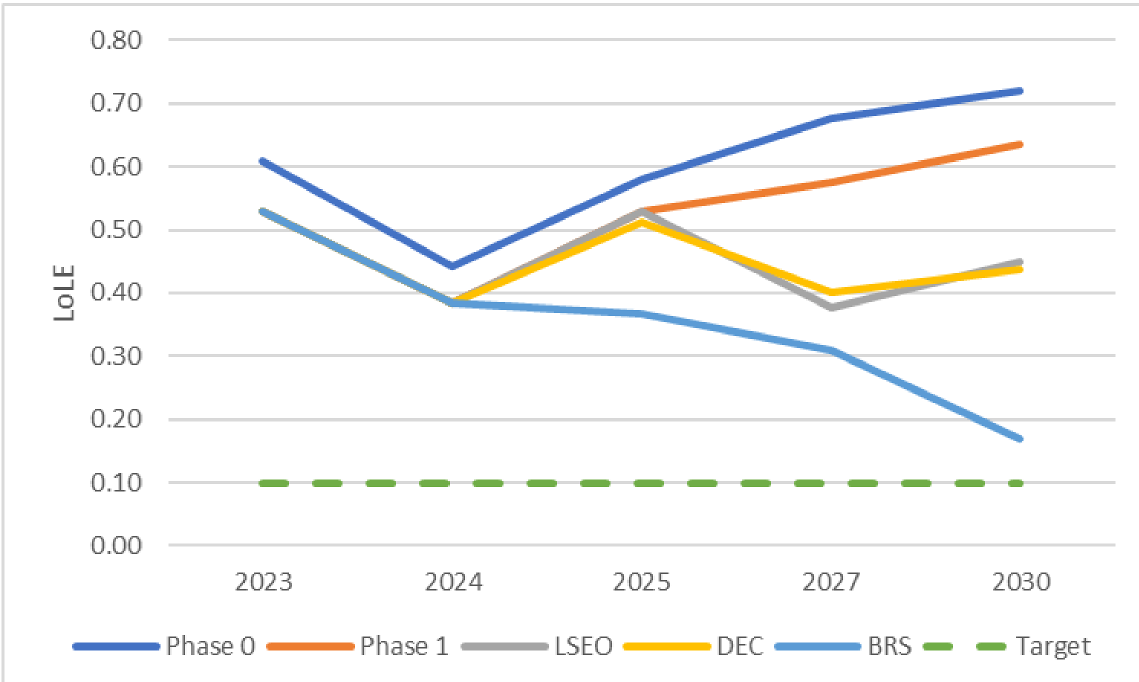
With respect to reliability, ICF evaluated several metrics:

- Loss of Load Expectation (LoLE), is the expected number of *days* per year during which resources are insufficient to meet customer demand. Most grid operators and regulators use a LoLE target of no more than 0.1, which is the equivalent of 1 day of bulk power system-caused outages every 10 years.
- Loss of Load Hours (LoLH), is similar to LoLE but demonstrates the expected number of *hours* per year during which resources are insufficient to meet customer demand.
- Expected Unserved Energy (EUE), is the total expected volume in MWh of load shed.

ICF's findings for cost and reliability are illustrated in the following sections.

Reliability impacts -- This analysis concludes that while the current market changes (Phase 1) and proposed alternate policies (Phase 2) do encourage some construction of new additional generation and storage, neither Phase 1 nor any of the Phase 2 options as currently conceived will reduce the probability of supply-caused outages below the PUCT's reliability goal of one outage event every 10 years. Figure 1 shows that while none of the Phase 1 and Phase 2 options achieve this target reliability level, the Phase 2-BRS option achieves better reliability faster than any of the other measures.

Figure 1: All ERCOT market scenarios will produce worse Loss-of-Load Expectation (LoLE) than target

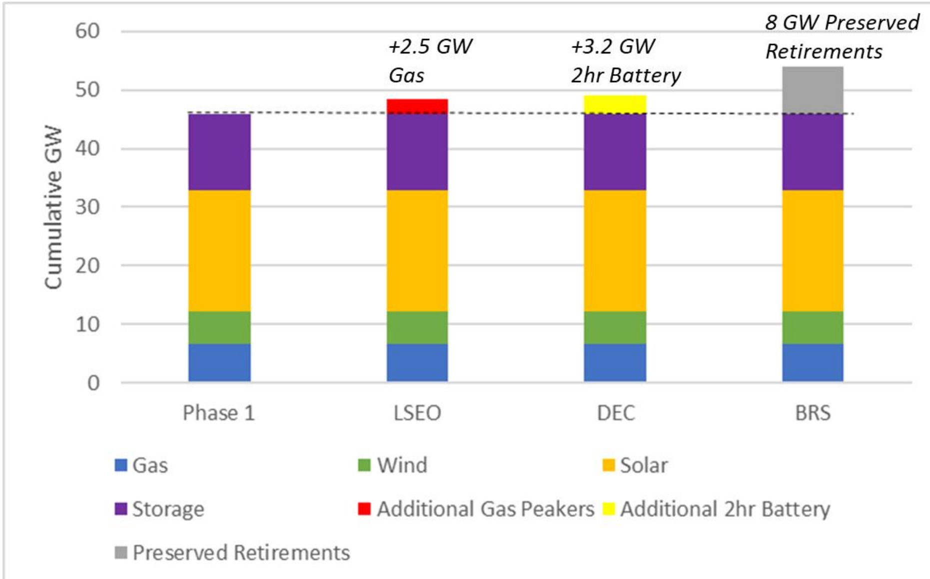


Phase 1 measures now in effect have already improved ERCOT reliability relative to the Phase 0 (2021 Uri) market conditions, with power plant winterization and increased Emergency Response Service ("ERS", compensated industrial demand response) program budgets driving much of that improvement.

It is important to note that none of the Phase 2 market reform options will deliver any substantive reliability improvements over the next two years (2023-2024) relative to the current Phase 1 market rules, because it takes time for additional new generation to come online once an investment signal is given.[4] Phase 1 measures do not appear to change the amount of new generation or storage that would be built relative to Phase 0. Both the Phase 0 and Phase 1 market rules would yield 45.9 GW of new generation and storage built in ERCOT by the end of 2030 (6.6 GW of new gas-fired capacity, 5.5 GW of new wind, 20.8 GW of new solar, and 13.0 GW of new storage). Competitive market economics and the higher maintenance costs and low fuel efficiency of older fossil plants are forecasted to push 2.9 GW of existing natural gas-fired plants and 5.1 GW of existing coal plants into retirement by 2030 under both Phase 0 and Phase 1. Figure 2 shows new resource additions by scenario.

[4] The BRS proposal could be implemented before 2025, but ICF does not forecast retirements of existing fossil plants until 2025.

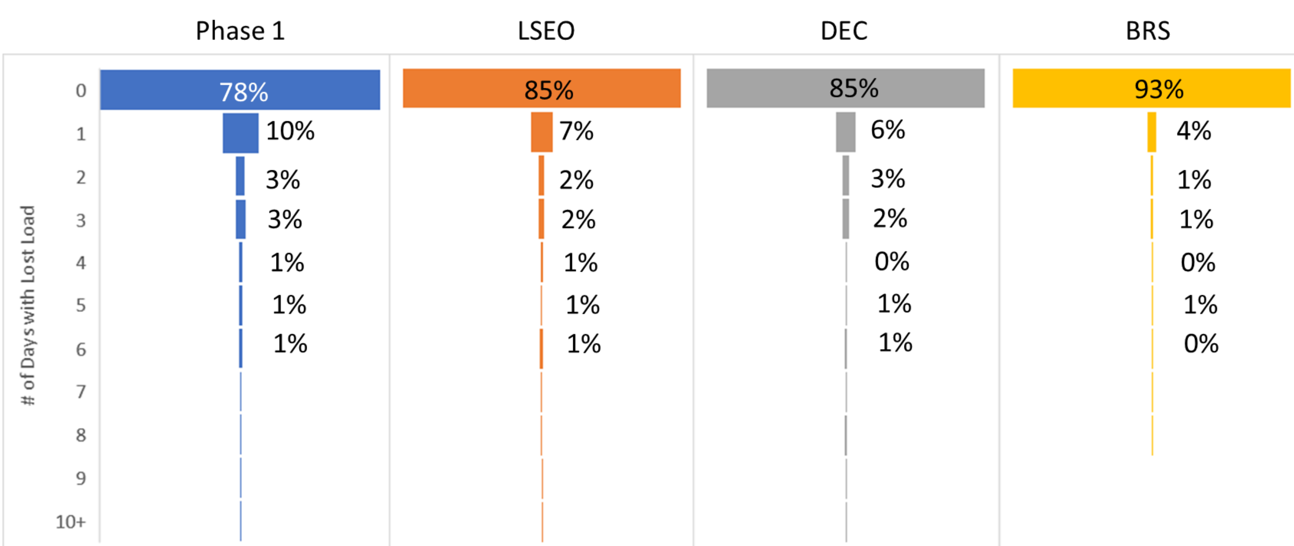
Figure 2 – Comparison of total generation added by 2030 in Phase 1 and Phase 2 scenarios



The proposed Phase 2 market reform options will not bring much additional new generation online – the LSEO proposal would fund 2.5 GW of additional new gas peaker plants by 2030, the DEC proposal would bring on an additional 3.2 GW of 2-hour battery storage units, and the BRS would preserve 8.0 GW of old fossil units that would otherwise retire, to be used only for grid emergencies.

Figure 3 shows a detailed distribution of loss-of-load risks across the 1,000 simulations for each scenario in 2030. The BRS shows the highest likelihood (93%) of having zero lost load in 2030, and just a 3% chance of having three or more days with lost load. The distribution of reliability risks under the LSEO and the DEC are similar. In both cases, there is a 6% chance of having three or more days of lost load.

Figure 3: Distribution of days with lost load in 2030 shows lowest risk under BRS



Cost impacts – The Phase 1 improvements are estimated to raise wholesale electric market costs by about $1.3 billion in 2023, a 5% increase over Phase 0 total costs. Phase 1 costs range from $825 million to $1.1 billion higher than Phase 0 costs between 2024 and 2030. The annual cost impacts of the Phase 2 policy options, measured as increments over Phase 1 costs, are shown below in Figure 4.

Figure 4 – Incremental cost impact over Phase 1 is highest for LSEO and negative for DEC

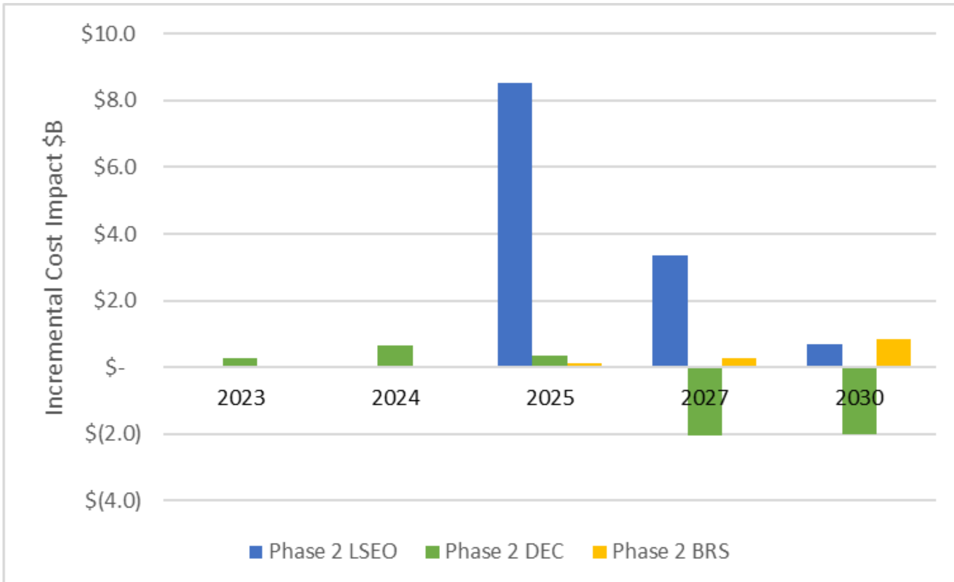
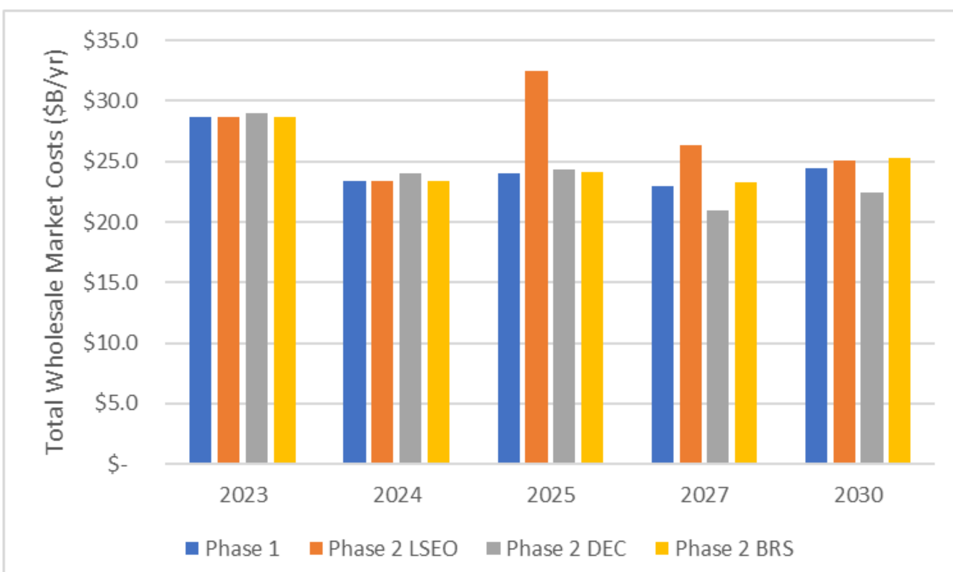


Figure 5 compares the sum total of wholesale market costs in each of the scenarios, including Phase 1.

Figure 5 – Comparison of total market costs by scenario



The LSEO proposal offers highest forecasted cost impact while delivering the least reliability improvements. The ERCOT market is already designed to raise wholesale electric prices when generation supplies are tight in order to incentivize capacity and availability. The LSEO proposal would provide extra compensation to generators ahead of time in addition to the existing incentive structures, creating a double payment. This premium could kick in as early as 2025, raising wholesale electric prices by a forecasted $8.5 billion – an increase of 35% over the costs of the Phase 1 market in a single year. LSEO costs could lower and stabilize in later years, but the forward payments to generators that begin in 2025 will not yield any additional new gas plants until the 2026-2027 timeframe and would not keep old gas or coal plants from retiring.[5] Over 2025-2030, on average the LSEO would increase market costs by approximately $3.8 billion per year. Critically, there are many uncertainties in the LSEO program design that could yield lower or significantly higher costs than this projection.

The BRS program in contrast has modest costs, on average increasing total market costs by about 2% over 2025-2030 (growing from $135MM in 2025 to $858MM in 2030, averaging $428 million per year). BRS costs are much smaller than the LSEO because the BRS is not a market-wide mechanism and targets payments to a limited subset of capacity, that is, resources that would otherwise retire but are instead kept operational and deployed only during emergency conditions. Critically, wholesale market prices would not be affected by the availability or operation of BRS-contracted units.[6]

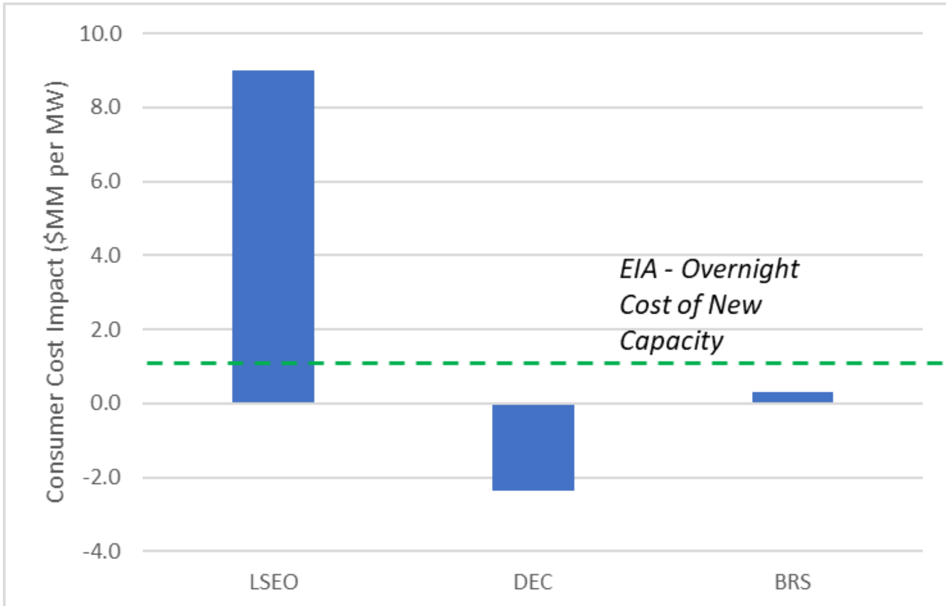
Like the BRS, the DEC program adds a new payment stream to a limited subset of resources – specifically, fast and flexible resources needed to stabilize supply particularly during solar and wind ramps and sudden generation or transmission losses. Unlike the BRS, units receiving DEC payments do participate in the wholesale market and affect market prices. Because the DEC incentives are forecasted to bring new storage and fast-responding generation capacity online, market prices will drop (especially scarcity prices) over time. On net, the DEC program therefore has negative total costs (i.e., it will deliver cost savings for consumers). These cost savings come about through reduced payments to generators in aggregate, which might be inconsistent with the PUCT goals for ERCOT market redesign.

Reliability improvement cost-effectiveness – Since the PUCT has prioritized dispatchable generation and storage capacity additions as a symbol of ERCOT power system reliability, we can compare the cost-effectiveness of each market alternative by comparing the value of the total incremental dispatchable generation and storage by 2030 attributable exclusively to each policy, divided by the policy cost. Figure 6 shows the dollar cost of each new MW of generation and storage brought on over the 2023-2030 period for each scenario, using only the incremental program capacity and cost relative to Phase 1 impacts. The LSEO option would cost consumers $9 million over 2023-2030 per additional MW of dispatchable capacity; in contrast, the DEC and BRS options pay a fraction of that cost (net costs to consumers under the DEC are negative). For comparison, the Energy Information Administration estimates the overnight capital cost[7] of a

[5] This is in part because, as new builds come online in response to the LSEO program, scarcity prices are forecasted to reduce and offset direct resource adequacy payments for existing generators over 2027-2030; many forecasted retirements of older power plants (65-70+ years) also occur due simply to plant age and equipment replacement needs.
[6] This could be accomplished through the existing Reliability Deployment Price Adder mechanism, with possible modifications, or another mechanism specifically designed to accompany the BRS.
[7] Overnight capital cost refers to all costs of equipment, construction, land, interconnection and other costs needed to bring a new power plant online *except* costs of financing debt during the construction process. https://www.eia.gov/electricity/generatorcosts/

new gas turbine in Texas to be about $1.3 million per MW in 2024. Both the DEC and BRS program costs are less costly per MW than this benchmark.

Figure 6: Cost per added MW of generation is highest for LSEO and low for DEC and BRS



Another way to measure the cost of reliability is to assess program costs relative to the number of hours of energy that cannot be served due to expected outages by 2030 for each policy option. The chart below compares policy option cost-effectiveness by dividing the net cost impact of each scenario by the total MWh of expected unserved energy (EUE) reduced in each policy scenario in total over 2023-2030. The Phase 1 measures are estimated to avoid about 13,200MWh of Expected Unserved Energy over 2023-2030 that Texas customers would otherwise have experienced as outages under Phase 0 rules, at a cost of $566,000 per MWh. On top of the improved reliability (lesser outage hours) and increased costs realized from Phase 1, the LSEO measure would cost almost $1.6 million per MWh of additional lost load prevented, while the DEC option would actually show cost savings (since, as described above, market power prices would reduce, producing savings for consumers in excess of direct DEC program costs).

Figure 7: Cost per MWh of reduced lost load, compared to Phase 1, is higher under LSEO and negative under DEC

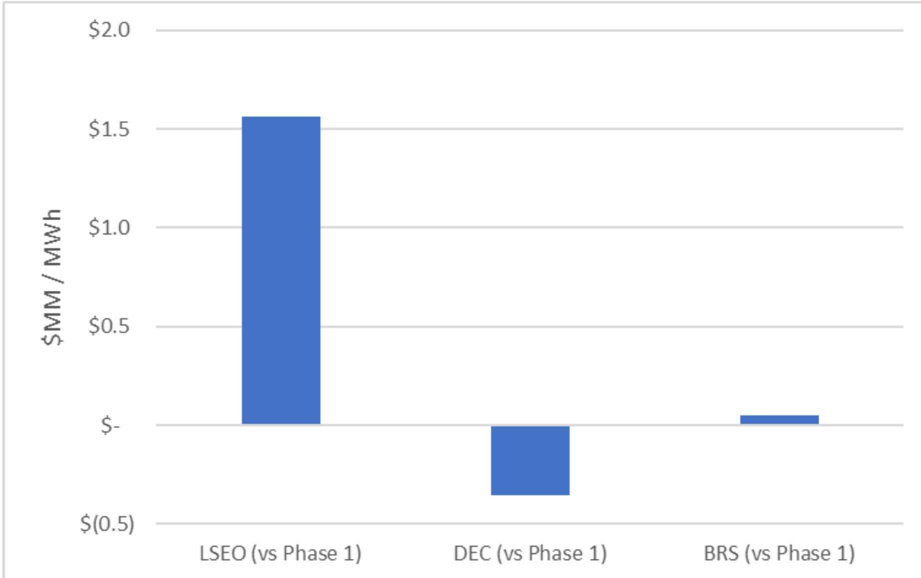


Table 1 summarizes some of the key cost and reliability metrics relevant for comparing the four new policy options. These metrics include:

- Total cost which represents the estimated total wholesale costs for the ERCOT electricity market, including energy, ancillary services, and additional program costs for new policy options (such as DEC payments) for the year indicated. This cost is the average cost for all of the 1,000 different combinations of normal and extreme weather, load, and other conditions used to test every policy scenario.
- Cost increase means how much this policy scenario costs, on average, compared to its baseline. Phase 0 is the baseline for evaluating Phase 1 market changes; Phase 1 costs are the baseline for comparing the three Phase 2 market options.
- Since one of the PUCT's stated reliability goals is to increase new generation builds to improve resource adequacy, New generation additions reflect how much additional generation and storage capacity is added under each policy scenario.
- Loss of Load Expectation (LoLE) means the expected number of days when available generation cannot serve all customer load. For reliability purposes, the common LoLE goal is to have only one generation shortfall over a ten-year period; this translates to 0.1 days of outage events per year. LoLE higher than 0.1 indicates lower reliability.
- Reserve margin means the percentage by which installed generation and storage capacity exceeds projected customer load on the peak day and hour of the year or season. Many U.S. grid regions have a reserve margin goal of 15%, meaning that there is at least 15% more capacity than forecasted peak load. However, a region can have a high reserve margin without having high reliability, as demonstrated in ERCOT during Winter Storm Uri. There are many ways of measuring installed or effective generation and therefore reserve margin. These differences are ***critically important*** for the LSEO option, since each resource's administratively-defined contribution to reliability will determine the amount of reliability assurance payments it receives. ICF used a variety of resource effectiveness methods to test the impact of alternate methods on the cost and effectiveness of the LSEO option (see chapter 3).

Table 1 – Summary of cost and reliability impacts for the Phase 1 and Phase 2 options

	2023	2024	2025	2027	2030
TOTAL WHOLESALE ELECTRIC COSTS ($Billion/yr)					
Phase 0	27,397	22,496	22,983	22,164	23,595
Phase 1	28,723	23,390	23,992	22,990	24,434
Phase 2 LSEO	28,723	23,390	32,510	26,347	25,118
Phase 2 DEC	29,005	24,054	24,341	20,960	22,443
Phase 2 BRS	28,723	23,390	24,128	23,258	25,283
COST INCREASE ($ Billion/yr)					
Phase 1 over Phase 0	1,327	894	1,009	825	839
Phase 2 LSEO over Phase 1	0	0	8,518	3,357	684
Phase 2 DEC over Phase 1	282	664	349	-2,030	-1,991
Phase 2 BRS over Phase 1	0	0	136	268	849
NEW GENERATION ADDITIONS (CUMULATIVE)					
Phase 1 over Phase 0	0	0	0	0	0
Phase 2 LSEO over Phase 1	0	0	0	2 GW gas CT	2.5 GW gas CT
Phase 2 DEC over Phase 1	0	0	1.4 GW 2hr Battery	3.2 GW 2hr Battery	3.2 GW 2hr Battery
Phase 2 BRS over Phase 1	0	0	0 new GW and 1.6 GW retirements prevented	0 new GW and 2.9 GW retirements prevented	0 new GW and 8.0 GW retirements prevented
LOSS OF LOAD EXPECTATION (0.1 = target)					
Phase 0	0.61	0.44	0.58	0.68	0.72
Phase 1	0.53	0.39	0.53	0.58	0.64
Phase 2 LSEO	0.53	0.39	0.53	0.38	0.45
Phase 2 DEC	0.53	0.39	0.51	0.40	0.44
Phase 2 BRS	0.53	0.39	0.37	0.31	0.17
SUMMER RESERVE MARGIN (ICF methodology)					
Phase 0	15%	15%	13%	13%	13%
Phase 1	15%	15%	13%	13%	13%
Phase 2 LSEO	15%	15%	13%	16%	16%
Phase 2 DEC	15%	15%	14%	16%	15%
Phase 2 BRS	15%	15%	15%	17%	23%

Summer reserve margin is shown in the table above. Reserve margin should be measured seasonally, particularly in ERCOT which has recently experienced new summer (2022) and winter (2021) peak loads with little or no excess capacity available. Reserve margins are only a way to predict how much variability (of higher-than-expected demand, lower supply, etc.) can be absorbed by the grid before load has to be shed. Historically, reserve margins in ERCOT are lower in summer than winter, but reliability has been worse in winter because there is more variability and risk. While power grids often aim for reserve margins to be at least 13-20%, minimum reserve margins in winter season may need to be higher to maintain reliability. Reserve margin calculations need to be done very carefully, otherwise reserve margin becomes a poor metric for assessing reliability. It is ICF's strong opinion that the methodology ERCOT uses to measure reserve margin in the biannual Capacity, Demand, and Reserves Report (CDR) is poor and creates the false perception that grid reliability is high and fast improving. This is discussed further in chapter 3.3.

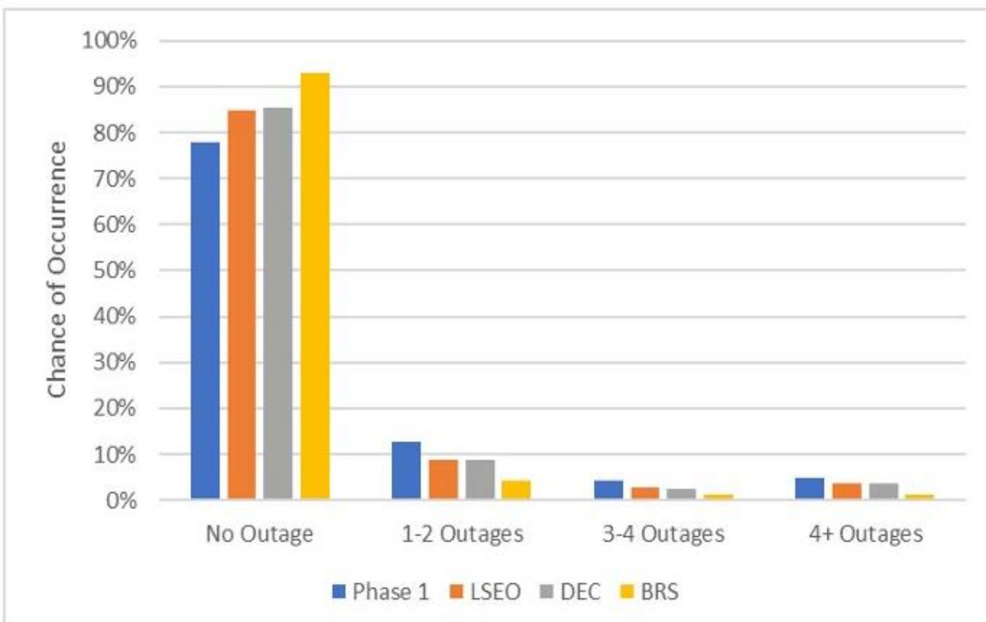
Lack of available capacity is only one reason the grid could lose load. Another risk is operational inflexibility – situations where there is enough capacity, but it cannot come online or ramp up fast enough. ICF projects that while operational inflexibility is becoming a challenge in ERCOT, the risk is manageable albeit at a cost (for example, frequent use of RUC). The DEC proposal would also help bring on new capacity to improve operational inflexibility. Our analysis shows that the primary risks ERCOT faces center on net peak load (demand minus renewable generation) and extreme weather. All three Phase 2 proposals improve reliability by helping address these risks, though with varying levels of efficacy and cost.

3 Discussion

3.1 Loss of Load Expectation and Critical Risks

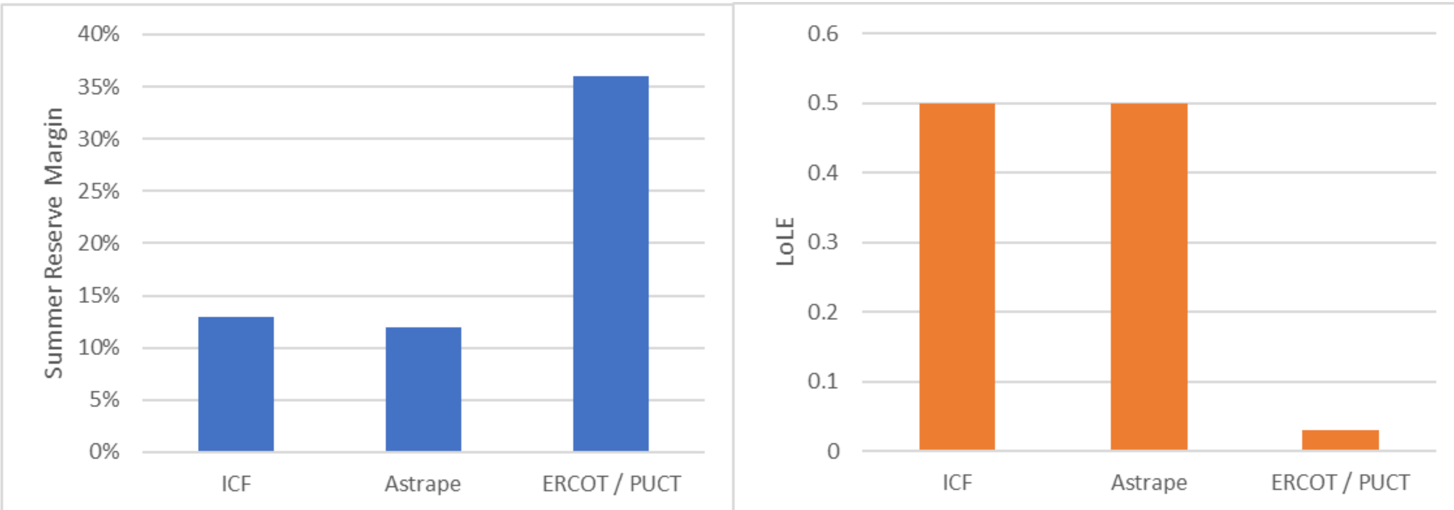
Figure 8 shows how many outages could occur in 2030 under the Phase 1 and Phase 2 policy options, after each policy has had several years to take effect. It shows that while there is a better than 76% likelihood that there would be no outages in ERCOT under all of the four options, and that each of the Phase 2 options might yield fewer future outages than Phase 1, the LSEO offers a slightly higher probability of multiple future outages than the DEC and BRS measures. Since most grid planners and customers seek to deliver less than one outage every 10 years due to generation shortfalls, these high outage occurrence rates indicate that none of the four ERCOT policy options evaluated here will deliver acceptable levels of grid reliability, but the BRS gets far closer than any other option.

Figure 8: Chance of outages under all four PUCT policies greatly exceed 0.1 LoLE



ICF finds that the ERCOT grid today has relatively poor reliability even after the Phase 1 reforms, with loss of load expectation (LoLE, or the average number of days per year with rotating outages) of approximately 0.5 days/yr – in contrast to recent statements by the PUCT that today's grid is highly reliable.

Figure 9: Significant differences between estimated Reserve Margins and LoLE from three recent sources[8]



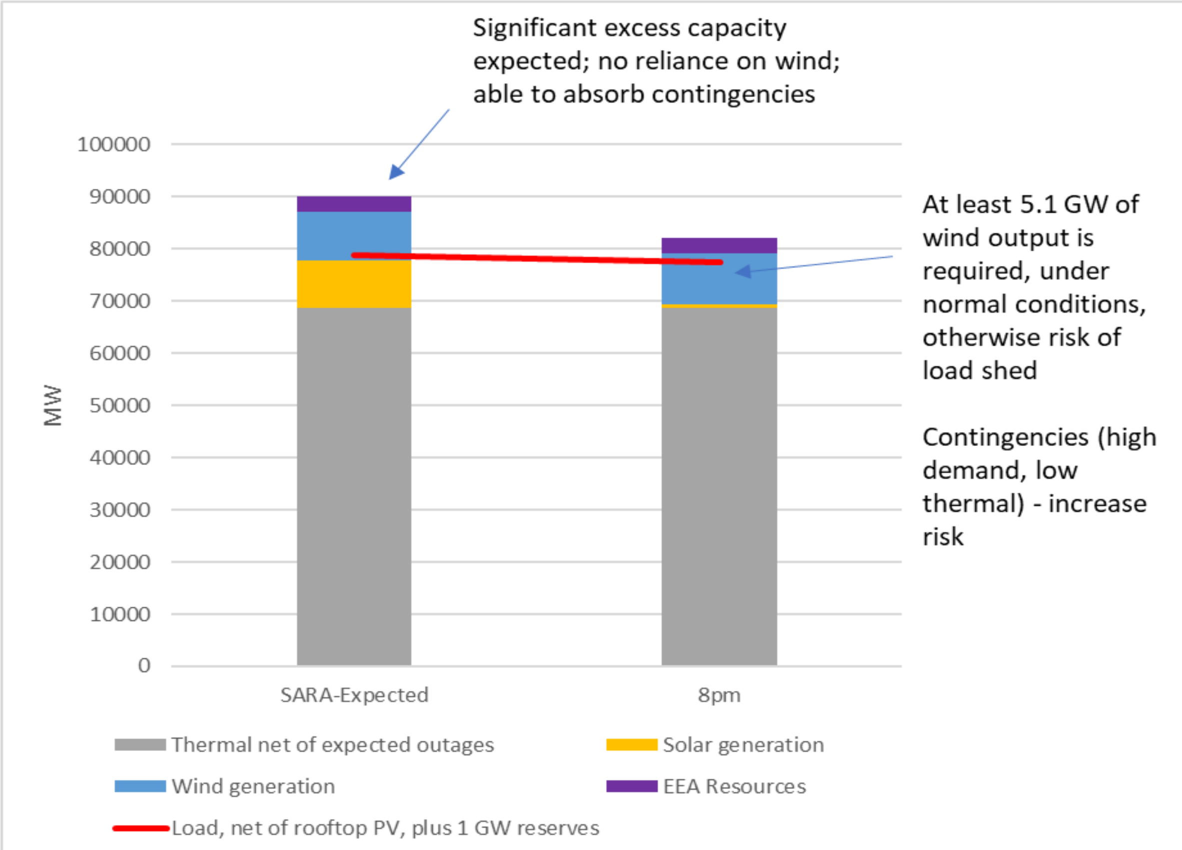
Astrapé Consulting, in the most recent study prepared for ERCOT[1], also estimated LoLE at 0.5 days/yr, near ICF's estimate. Astrape's study uses reserve margin assumptions and a modeling approach closer to ICF's than ERCOT's (e.g., Monte Carlo simulation of all hours of the year). Figure 8 above compares ICF's current study, ERCOT's May 2022 CDR, and the Astrapé study to show the gulf between ERCOT's calculation of reliability metrics and two external consultants (Astrapé and ICF).

A high reserve margin does not necessarily guarantee grid reliability. Differing ways to measure reserve margins and different resources' effective contributions at times of grid stress can have a significant effect on reported reserve margins and actual reliability. ICF's methodology differs significantly from that of ERCOT in our estimate of current reserve margins. While ERCOT reports summer reserve margins around 36% for 2023, ICF analysis indicates actual reserve margins closer to 13%. This difference is arises because ERCOT's estimate focuses only on the seasonal peak load hours, which are not necessarily the hours of highest risk. ICF's analysis considers all hours of the given season.

ICF believes ERCOT's calculated reserve margin forecasts inappropriately focus solely on risks during the season peak (gross) load hour. However, much greater risks occur during the net peak load hour, defined as total load minus renewable generation. For example, Figure 10 below compares the ERCOT 2022 Summer SARA report's forecasted risks during the gross peak load hour (4-5 PM in ERCOT's load forecast) to the risks approximately 3 hours later on the same day:

[8] Notes: Astrape's Base Case uses study year 2024, but the focus of the study is on the sensitivity of LoLE and economics with respect to reserve margin. The ICF and ERCOT / PUCT values shown are for 2023. ICF's forecasts for 2024 are similar to 2023.

Figure 10: Comparison of Summer SARA 2022 peak load hour to net peak load hour

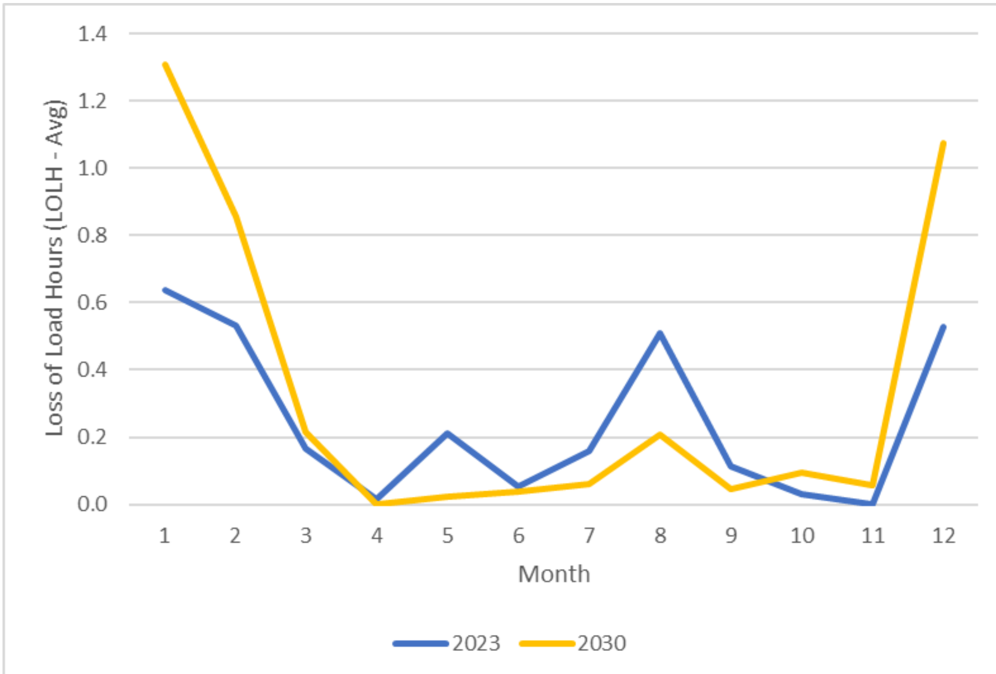


The approximately 12 GW of extra reserves available under the SARA's "Base" scenario falls to just 3 GW by the time the sun sets during the 8-9 PM hour. Over this time, gross load typically drops by 4-5 GW, but rooftop PV output also falls, offsetting some of the loss. Typically, wind generation increases somewhat during this time, but wind output during the summer is highly variable; this leaves very little room for other contingencies to occur without triggering a grid emergency.

The SARA report only shows load shed under a combination of extreme events: either the extreme peak load plus extreme unplanned outages scenario, or the high peak load combined with extreme outages and extreme low wind conditions. Multiple extremes occurring at once is a very low-probability event. However, at 8 PM on a typically summer peak-load day, only one significant SARA contingency needs to occur to cause loss of load: either low wind, high demand, or high outages. Single-variable contingencies are much more likely than multi-variable contingencies. Additionally, the above analysis is for 2022 summer. As solar capacity grows rapidly in ERCOT, net-peak will continue to shift later in the day, shifting the timing of grid scarcity and higher energy prices.

Historically, peak demand more often occurs in summertime and therefore the reliability focus has typically been on summer reserve margins and risks. Since Winter Storm Uri however, a greater emphasis has been placed on winter reliability. One of the first policy initiatives following Uri was to mandate improvements in generators' ability to withstand more extreme winter low temperatures. While this effort does improve reliability in ICF's forecasts, ERCOT still faces significant loss of load risks in winter and those risks will grow substantially by 2030 due to the changing resource mix, while summertime loss of load risks will abate. Figure 11 below shows monthly distribution of lost load hours in 2023 vs 2030, indicating winter risks rising while summer risks drop:

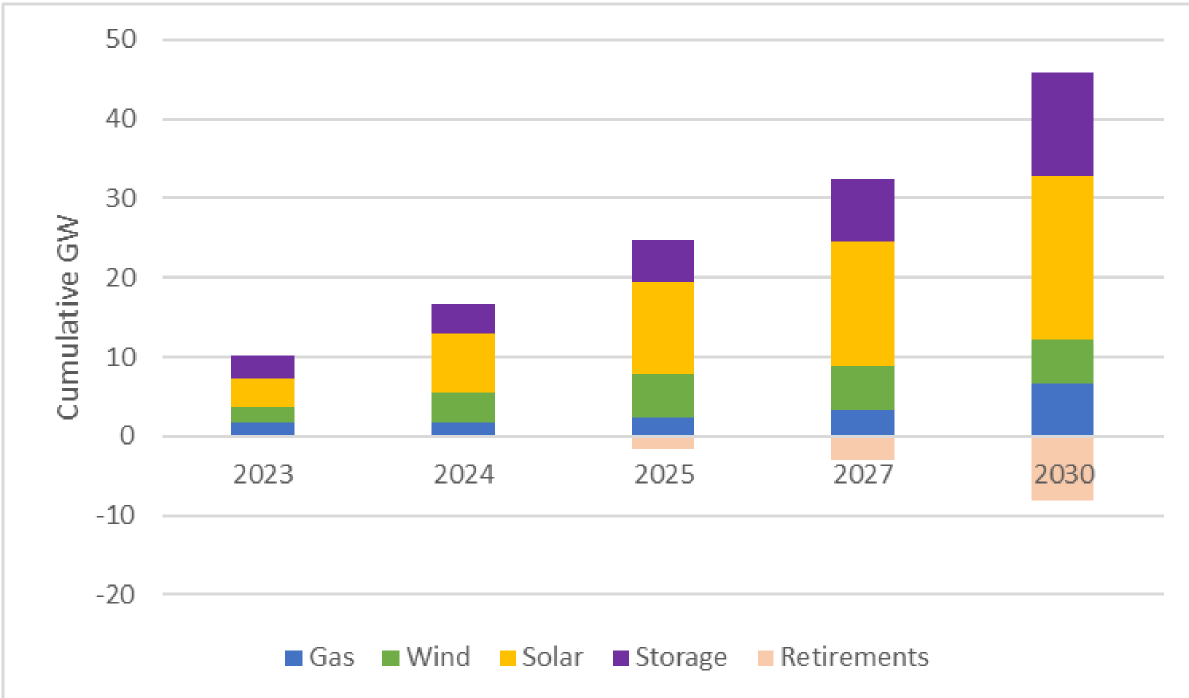
Figure 11: Winter outage risks increase in winter as solar resources increase under Phase 1 scenario[9]



The change in risk is due to the forecasted changes in the capacity mix, tested against 1,000 cases of normal and grid-stressing weather and resource outage conditions. Figure 12 below shows new supply entrants by type (nameplate capacity shown) in Phase 1. Solar generation resources are more valuable in summer months because they produce most when customer demand is highest, but solar output aligns poorly with peak demand in winter. The second largest source of new capacity is battery storage. Like solar, battery storage is more effective in summer, because risks during summer concentrate primarily from 5-9 PM on weekdays, when customer load stays high as solar generation falls. In contrast, renewable output and thermal generation are more uncertain in winter, demand patterns are less peaky, and demand uncertainty is higher. These factors often combine to yield longer stretches of risk to the grid in winter months. Over the past 15 years, every significant summer emergency outage event in ERCOT has lasted 4 hours or less; but ERCOT winter load shed events have been much longer (>5 hours consecutively during 2011, and nearly three days consecutively during Uri).

[9] Loss of Load Hours (LOLH) is similar to LOLE. While LOLE measures number of days in which an outage occurs, LOLH measures the total number of hours with loss of load. For example, if load was shed for three hours for one day, LOLH would be 3 while LOLE would be 1. We show LOLH on this graph because it is more granular and therefore better indicates differences in risk during shorter time periods (e.g., monthly, in the graph shown, vs annual).

Figure 12: Increasing solar and storage resources under Phase 1 Scenario



Winter reliability risks are exacerbated by higher uncertainty in weather-driven winter demand. While ERCOT's weather-normal peak forecast has under-forecasted summer peaks by 5-10% at worst, ERCOT winter peak could be under-forecasted by 30-40% (see modeled distributions in the Appendix) due to dramatically higher electric resistance heating in uninsulated homes as temperatures fall. Even if generator performance during these events improves under Phase 1 due to power plant winterization requirements, winter storms with zero or negative temperatures in major ERCOT load centers will still prove very challenging to the grid. During Winter Storm Uri, ERCOT would still have been generation-short even if generator outages and fuel deliveries were normal, although the resulting loss of load events would have been smaller and shorter. Thus, power plant winterization by and of itself is not a complete solution to winter reliability risks, especially as reliance on solar and storage grows.[10] Notably, FERC's recent 2022-2023 Winter Assessment also shows ongoing risks to the ERCOT grid in winter.

These evolving seasonal and time-of-day changes in risk impact the effectiveness of Phase 2 proposals, and should be taken into account in program design.

3.2 Phase 1 – Current market and operational rules

Phase 1 included numerous market rules changes. The most notable changes include lowering the systemwide price cap from $9,000/MWh to $5,000/MWh, increasing the minimum contingency level (MCL) in the ORDC

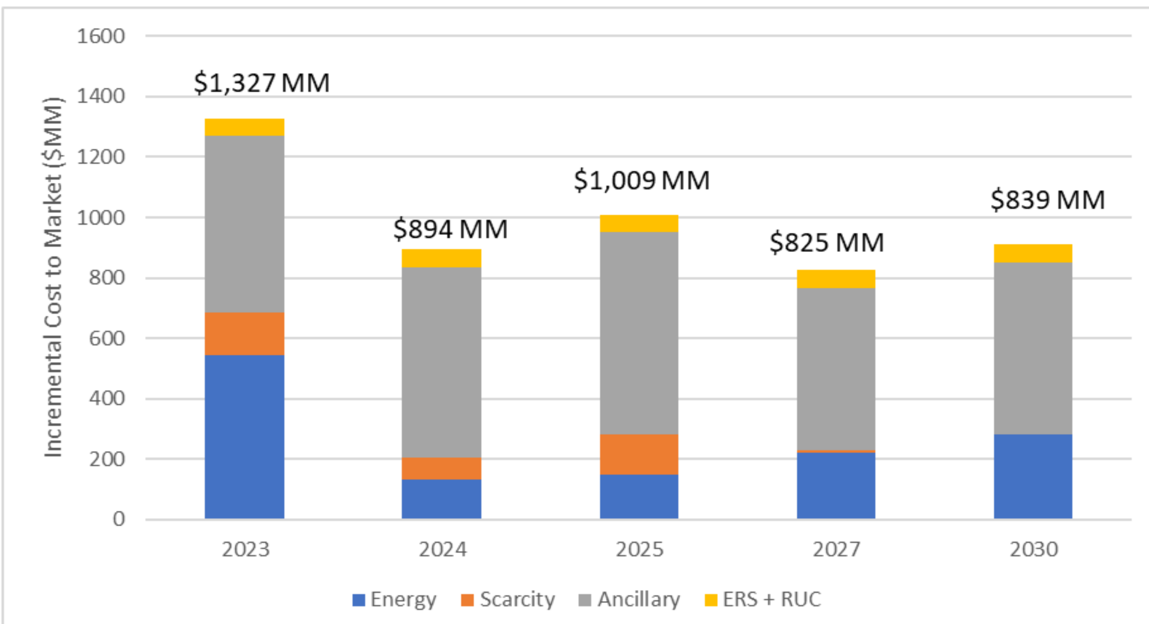
[10] Note that this analysis assumes power plant winterization with fully reliable natural gas and coal supplies, even though there has been limited progress to date in assuring winterization of Texas fuel supply systems.

from 2,000 MW to 3,000 MW (shifting the ORDC "outward"), increasing volumes of non-spin procurement significantly, accelerating deployment of the ECRS ancillary product, mandating winter weatherization of power plants, using conservative demand forecasts when evaluating reliability unit commitment (RUC) needs, and raising program budgets in emergency response services.

Phase 1 Cost Impacts

As shown in Figure 13, the cost of ERCOT's Phase 1 reforms is around $900MM/yr on average, or about 4% increase in total costs. Ancillary costs make up the largest source of Phase 1 incremental costs, mostly for higher quantities of non-spinning reserves. The higher procurement of ancillary services also raises energy prices, since generators that commit to provide ancillary services must hold capacity out of the energy market in order to keep it available for ancillary services provision.

Figure 13: Consistently higher Phase 1 incremental market costs compared to Phase 0, 2023 through 2030

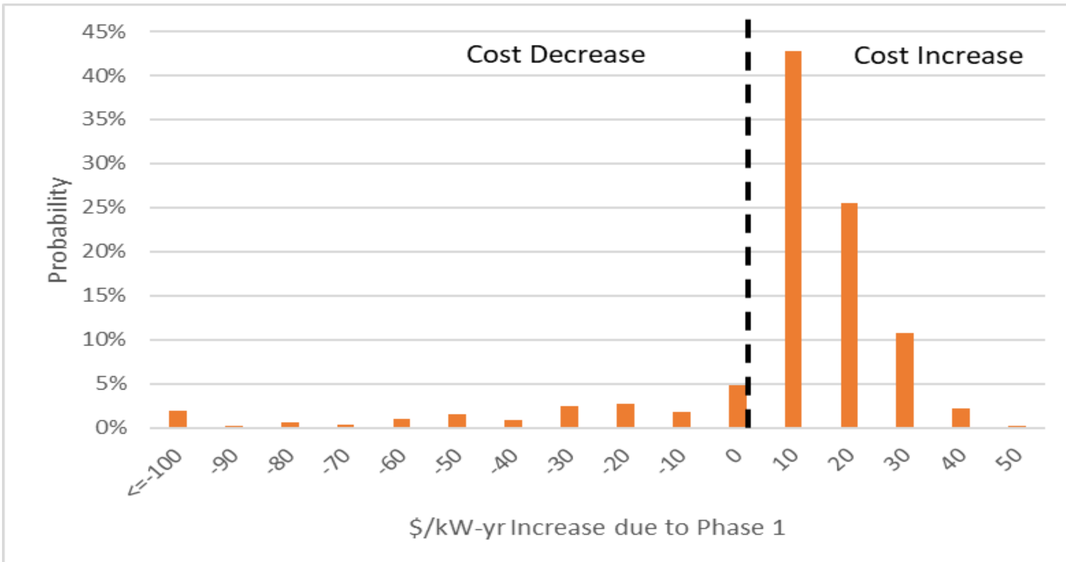


Phase 1 changes also raise energy scarcity prices. The total scarcity cost increase reflects the aggregate impact of higher MCL and lower high system offer cap (HCAP, the maximum price in the system, now $5,000/MWh instead of $9,000/MWh in Phase 0).[11] The higher MCL raises prices in many hours, even as the lower HCAP lowers the maximum price. The result that more generation generally receive lower scarcity prices in a few hours of the year but higher scarcity prices in many more hours of the year (and on net, more dollars overall on average in all modeled years).

[11] The ERCOT Independent Market Monitor often refers only to the change in MCL when commenting on the impacts of ORDC changes in Phase 1. This is technically correct, but both parameters influence scarcity pricing and the magnitude of total scarcity payments to ERCOT suppliers.

As shown in Figure 14 below, the 1,000 cases analyzed for Phase 1 show a range of outcomes depending on the weather and other random variables. During extreme years, with many hours at the price cap, the Phase 1 lower price cap reduces costs to the market (negative values to the left of the vertical dotted break-even line). During most years, however, the impact of the MCL increase is much greater (positive values to the right of the vertical break-even line) because there are few hours when supply is so tight that energy plus scarcity prices reach the price cap.

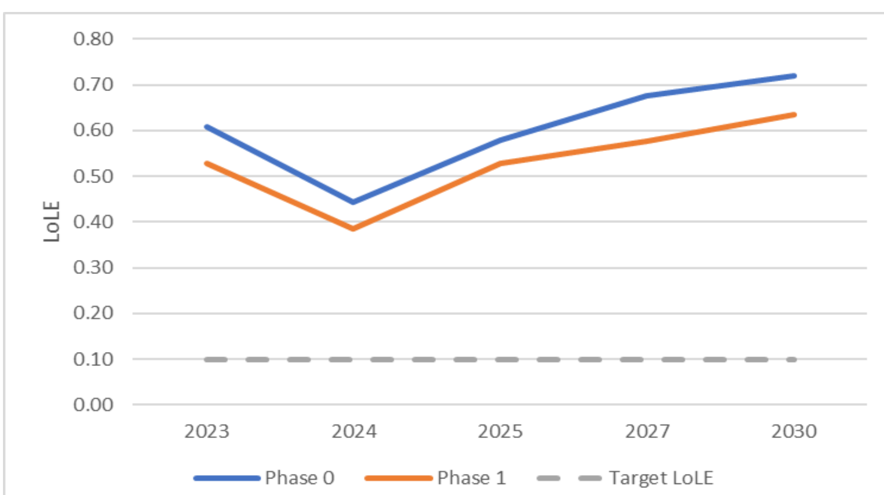
Figure 14: Very high likelihood of scarcity cost increases in 2023 due to Phase 1 changes



Phase 1 Reliability Impacts

As shown in Figure 15, Phase 1 measures improve reliability in terms of LoLE, but does not come close to achieving target levels:

Figure 15: Phase 1 improves Loss of Load Expectation relative to Phase 0, but remains higher than target



Phase 1's main benefits for system reliability result from the higher budget for ERS (attracting an additional 500 MW of ERS capacity in our model12) and winter power plant weatherization. The reliability impacts of ERCOT's "conservative operations" (aggregate impact of higher ancillary procurement, conservative demand forecasting and use of Reliability Unit Commitments (RUC)) are modest but costly, especially in the day-ahead market. This is because ERCOT is using ancillary services, RUC payments and conservatively high demand forecasts to give more generation higher payments to be available in real time in the event that demand proves much higher and generation proves insufficient. However, under Phase 0 rules, the $9,000/MWh price cap and associated ORDC provided stronger incentives for generator availability than the incentives under Phase 1's $5,000/MWh price cap. The fact that ERCOT is calling for and generators are providing additional non-spinning reserves and RUC resources does not prove that these additional precautions averted actual capacity shortfalls or operational loss of load. Rather, the increased non-spinning reserve and RUC requirements are protecting against the possibility that a sudden emergency occurs that could not have been handled using slow-start units that were not already online. The only way to prove that the higher Phase 1 non-spinning reserve and RUC requirements are improving reliability would be to show that those generators would be offline or withholding production during high-priced scarcity hours if not for the RUC and non-spinning reserve compensation.

3.3 Phase 2 – Load-serving Entity Obligation (LSEO)

The LSEO seeks to address future resource adequacy challenges by obligating all ERCOT load-serving entities (LSEs such as competitive retail electric providers and municipal and electric cooperatives) to acquire enough firm future resources to cover their share of future demand levels, or pay a penalty for the failure to acquire sufficient forward capacity. The LSEO is comparable to Resource Adequacy (RA) constructs in markets such as MISO, SPP, and CAISO. It would assign credit to generators based on expected availability during forecasted peak demand periods. The LSEO proposes to use a 3-year-forward forecast period. If total generation resources in the market are forecasted to be insufficient to meet peak demand plus a minimum reserve margin need, ERCOT declares a future shortfall and "showing" of need for capacity in that forecast year. At that point, load-serving entities (LSEs) would have to contract with generators for sufficient capacity to cover their portion of forecasted peak load for the period with the "showing of need". These contracts would create a price for credited capacity (referred to here as the RA price).

While the LSEO would not be binding on LSEs for years without an ERCOT resource shortfall showing, ICF projects that RA contracting and associated RA payments will occur in those years nonetheless. LSEs would be incentivized to contract with resources prior to ERCOT's forward analysis, because if ERCOT finds that a future year will be resource-short, the LSEs would have to contract with every existing generator in the market and bring new resources online quickly to cover their peak capacity obligation. This situation would give huge leverage to existing generators to demand high prices for their capacity. An LSE which contracted ahead of time for its load would therefore be at an advantage. As such, ICF projects that LSEs will contract for their

[12] This estimate may be optimistic given recent rules changes allowing ERS to be deployed earlier as the grid approaches emergency conditions, which may increase costs for participating resources and consume some or all of the additional program budget.

LSEO capacity obligation in all years, even in those years that without shortfall "showings" and penalty payment obligations.

Commentary on LSEO Scenario

To date the public information on the LSEO represents more of a conceptual framework than a specific proposal. Key missing details include specifics related to how resource accreditation, reliability standards, and cost caps will be determined. These technical details are critically important to evaluating the program as a whole and the regulatory or administrative decisions related to these key variables will drive a wide set of possible LSEO cost and reliability outcomes.

The most critical LSEO design parameter is how to structure and apply resource accreditation – how much of each resource to assume will produce reliably, at what level, during peak hours and seasons, which in turn affects estimated reserve margins during critical operating periods. Credible sources use widely differing assumptions with respect to resource accreditation and reserve margin crediting. Considering this uncertainty, ICF applied seven different methodologies for evaluating resource credit levels:

- First, we adapted ELCC values from E3's recent study, "Resource Adequacy in the Desert Southwest" (2022).[13] While the desert southwest (DSW) system is different than ERCOT, the climate / temperature profile and renewable resource patterns are not overly dissimilar, and this is the closest parallel we could find for an E3 study.
- Second and third, we show ERCOT's outlook:
  - In the CDR (which uses nameplate values for thermal), and
  - The SARA (which uses typical outage levels in its baseline scenario)
- Fourth, we adapted ELCC values from Astrapé Consulting's "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024" study[14].
- Fifth and sixth, we show ICF's projected ELCC values derived using the SRAM Monte Carlo model,
  - On a thermal-nameplate ("ICAP") basis, the same as the CDR, and
  - Thermal derated based on average forced outage rates ("UCAP") basis
- Seventh, we pulled actual unit outage rates reported by ERCOT over the past 12 months (9/15/21 through 9/15/22) and used the seasonal average performance for each unit.

ICF's standard approach for showing reserve margins in ERCOT is approach number 5 ("ICF-ICAP"); this is the case for which cost numbers are shown in the Summary of this report.

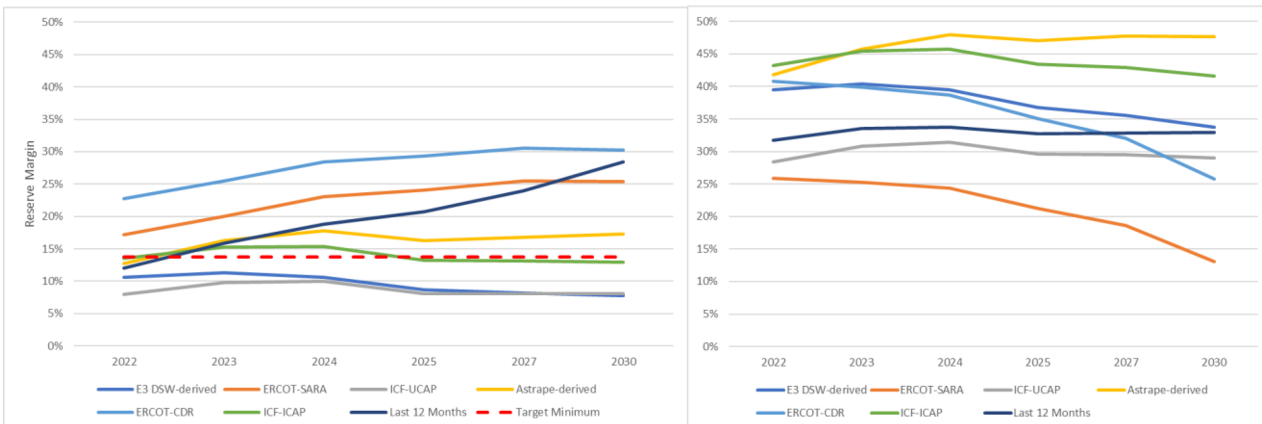
Figure 16 below shows the resulting range of summer and winter reserve margins. While all of the resource accreditation methods use the identical underlying set of generation and storage resources, the differing resource accreditation methodologies yield dramatically different reserve margins. Equally important, the different accreditation methods yield different rankings for summer versus winter, reflecting differing performance capabilities in each season for the same underlying resource portfolio. Thus, the choice of resource accreditation method in implementing the LSEO policy will determine which resources get how much

[13] For the E3 DSW-derived and Astrape-derived cases shown, the values utilized represent ICF's adaptation / interpretation of publicly-available information in the referenced reports. E3 and Astrapé were not involved in any way in this study and are not responsible for the specific data and assumptions used in this analysis.

compensation for LSEO resource adequacy and is critically important in determining how much the LSEO policy as a whole could cost Texas electric customers. The wide differences between accreditation method impacts also illustrates how to manipulate the total cost of the LSEO and the distribution of LSEO payments among resources, tempting market participants to try to game the choice and details of the LSEO accreditation method.

Figure 16: Future summer and winter reserve margins vary widely due to ELCC assumptions

Summer reserve margins **Winter reserve margins**



The "target minimum" reserve margin shown is 13.75% (dashed red line in Figure 16), which has loosely been ERCOT's standard since 2011. At present the LSEO methodology for determining the trigger minimum reserve margin (or other metric/standard) remains unspecified except in terms of general principles. Reserve margin is only a reasonable indicator of reliability to the extent resource accreditation reflects actual value to the grid.

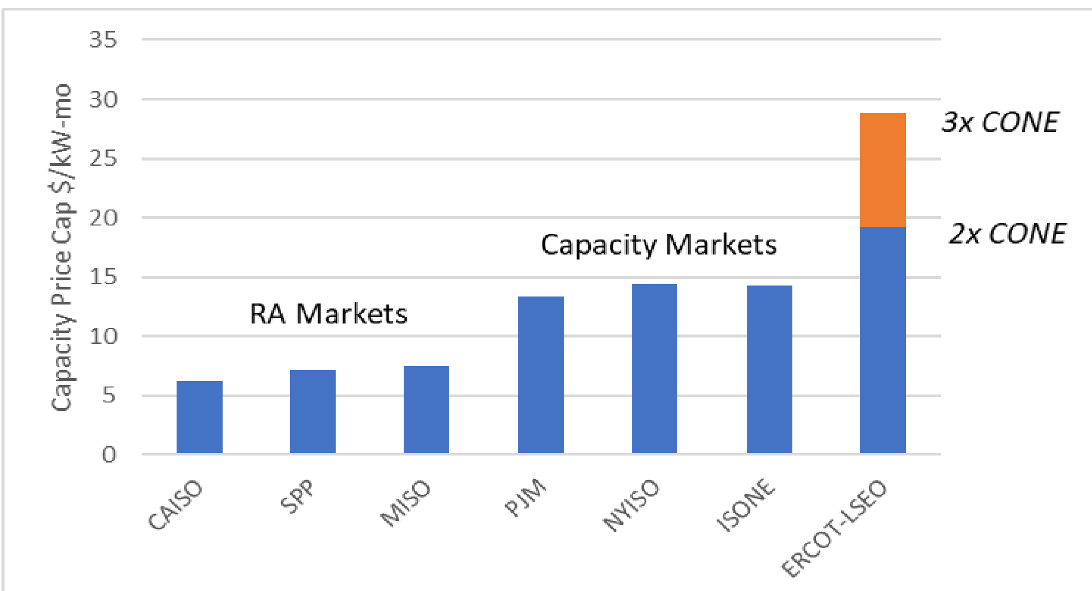
Since winter demand levels are significantly more variable than summer, and the variability in unit outages is also higher, ERCOT should use a higher minimum reserve margin or reliability metric in winter than summer to yield the same level of reliability and avoid further outages. As the resource accreditation and associated reserve margin options above show, future ERCOT winter resource adequacy could be significantly tighter than summer.

Treatment of solar and battery storage resources is a critical differentiator between these resource accreditation and reserve margin options. Solar and battery resources currently comprise nearly 85% of the current ERCOT interconnection queue and are projected to be the dominant sources of new generation capacity over the next 1-5 years. Gas resources total 10 GW or approximately 4% of the queue, of which around 3 GW are already projected to come online by 2027 and 6.5 GW by 2030 in the Phase 1 scenario. Since batteries and solar resources tend to have shorter project lead times than other technologies, solar and storage are the largest pool of potential capacity that could be quickly incentivized to come online. However, there is a wide range of estimates as to the effective contribution of solar and storage to reserve margin. For example, the ERCOT CDR gives high 81% effectiveness credit to solar resources in summer, but zero credit to storage. In contrast, ICF finds that after approximately 20 GW of solar comes online, the incremental reliability value of additional solar capacity is effectively zero,[14] but that 1-hr storage should be given at least 35% credit (and 4-hr storage around 90% credit).

The reason reserve margin uncertainty matters are because the resource adequacy[15] (RA) price and associated market costs are highly sensitive to reserve margin, especially when near- or below target reserve margin levels. Under these conditions, contract prices will increase to near the resource adequacy penalty cap, because load-serving entities would have to pay the penalty/cap price for any shortage of deficit, giving generators significant leverage. Again, the season-specific accreditation methods and values selected, in combination with whether load forecasts are high or low, will have an outsized impact on when and how much future resource scarcity is recognized, and thus how much the LSEO will cost customers.

The LSEO proposal mentions using 2-3x cost of new entry ("CONE", the total levelized cost of a new generation unit of specified technology) as levels for the Backstop Capacity Price (shortage penalty price) that would be charged to load-serving entities that have not acquired all of their LSEO-required forward capacity obligation. This is a notably higher shortage price compared to other resource adequacy markets that cap prices at 1x CONE[16], and the central capacity markets that cap prices at around 1.5x CONE, as shown in Figure 17.

Figure 17: Other regions with capacity mechanisms use much lower Backstop Capacity Prices[11]



Historically, no U.S. market with an RA or capacity market has ever experienced system-wide prices at the penalty/backstop capacity price[17] due to an overall shortage of forecasted reserve capacity. This is partly

[14] Astrapé reached a similar conclusion in a preliminary update to the referenced 2021 study, presented to ERCOT at the end of August 2022.

[15] The LSERO has some differences from established RA markets like SPP or CAISO, but for ease of common understanding, we use the term RA here in reference to credited MW or the average contract price per credited MW.

[16] Most markets make provisions for individual capacity bids above the ceiling if actual higher costs can be demonstrated for a given unit; this is quite atypical (except occasionally in CAISO which has the lowest "normal" backstop price in its Capacity Procurement Mechanism).

[17] Sub-regions have occasionally cleared at the cap in some markets.

because RA/capacity market constructs were often introduced into markets at a time of excess systemwide capacity,[18] helping assure a smooth path towards optimal reserve levels. However, under several of the possible interpretations of reserve margin discussed previously, ERCOT could be in a market-wide shortage of reserve capacity in the first year of the LSEO, likely pushing RA prices to the penalty cap. This is true whether the first year is 2025, 2026, 2027, or even later. Thus, there is a *significant risk* of having extremely high LSEO costs and a market scramble for capacity upon program implementation before the market has time to build more generation, demand response capability, or having load-serving entities reduce the amount of load they have to cover with supply reserves.

The current LSEO proposal incorporates a 3-year forward window to give time for new resource builds to come online and rectify an upcoming shortage. However, for several reasons this may not prevent a chaotic outcome if reserve margins are below target in the first year of implementation:

- Even if sufficient capacity can come online quickly to meet the minimum resource adequacy requirements, generators would still have leverage to demand very high contract prices against the threat of penalty pricing unless new resources overshoot and deliver enough excess capacity to give load-serving entities some procurement options and discretion. The LSEO proposal does not provide enough detail as to how it would mitigate suppliers' market power, or cap supplier bids apart from the penalty/shortage price, which could help with this issue.
- A 3-year look-ahead is sufficient time to bring online new generation *only if* there is a pool of shovel-ready projects that have already been sufficiently developed. There is a significant pool of shovel-ready solar and storage projects in the ERCOT interconnection queue today. If solar and storage are given high resource adequacy credit, they may be able to relieve a shortage both on paper and in actual operations. However, solar and storage face the greatest uncertainty over RA accreditation levels; again, note that ERCOT's current reports give zero reliability credit to storage. In contrast, there are few shovel-ready natural gas projects in the ERCOT interconnection queue today, apart from several peaker projects which are already assumed to be coming online in this analysis (and thus will make money from the LSEO but whose build decisions, and therefore reliability impacts, are not influenced by it).
- Current supply chain constraints and increasing timelines for interconnection studies could compromise completion of new projects within the timeline. Many new builds of all technology types today are experiencing significant delays.
- The fastest-responding new resources could be demand response, distributed resources and energy efficiency initiatives. The PUCT should consider how to accredit and encourage these resource options to give them credit for meeting LSEs' adequacy obligations, in order to reduce generator market power, increase reserve margins, and reduce total LSEO implementation costs.

LSEO cost impacts

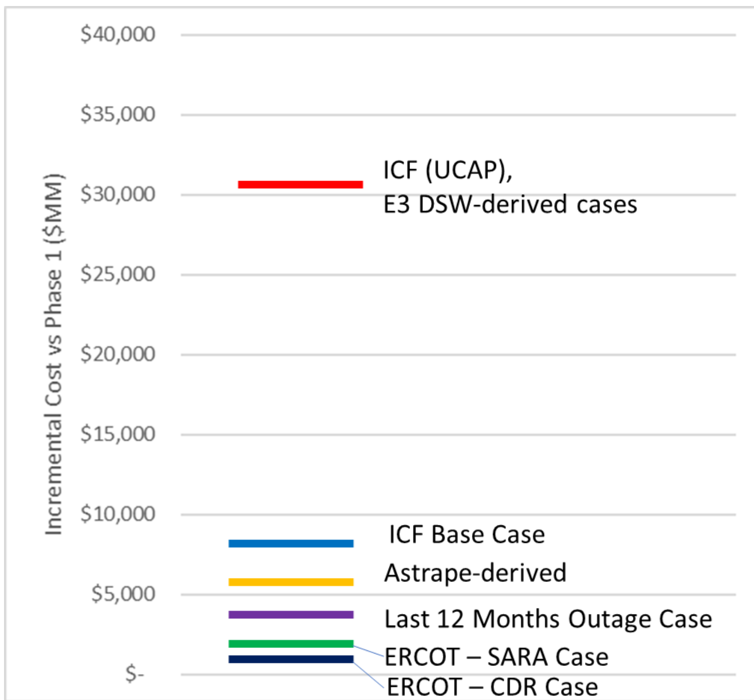
Figure 18 below shows resource adequacy program costs under the various resource accreditation schemes and reserve margin outlooks described above. In a worst-case scenario (such as what could occur under credit

[18] The closest parallel is CAISO's RA market, which was introduced following blackouts in 2000-2001. However, by the time RA obligations became binding, the market again had excess capacity due to direct state contracting with generators. CAISO's program also has the lowest cost cap and some of the strictest market power mitigation rules among RA markets. This is in contrast to the proposed LSEO.

levels derived from E3's referenced DSW study are used, or ICF's UCAP case), there would be a shortage of around 4 GW of reserve margin-counting capacity in the first year of implementation. These two cases and the Astrapé-derived ELCC case are the most likely and appear consistent with the general resource crediting principles outlined in the LSEO proposal filed at the PUCT.

In these scenarios, if LSEO were first implemented in 2025, LSEO resource adequacy charges to customers in that initial year would likely be near or at the penalty cap. Assuming a penalty cap of 3x CONE for a combustion turbine, RA costs could total over $30 billion dollars in the first year, more than doubling total market costs relative to Phase 1 costs. Other resource accreditation methods would yield incremental program costs in the range of $2-8 billion per year. If reserve margins are determined to be very high (e.g., as shown in the CDR), the LSEO could have lower costs but would be unlikely to influence supply and therefore reliability.

Figure 18: LSEO program costs vary widely and could significantly raise total market costs over Phase 1 levels



Because of its high sensitivity to resource accreditation and other parameters, the LSEO would massively increase the power and impact of regulatory and administrative decisions compared to the market today. This different power dynamic could cause political calculations (related to these regulatory and administrative decisions) to have more effect than economic competition in determining market outcomes and therefore grid reliability and costs overall. Outside ERCOT, other regions with RA markets are dominated by traditional, largely-regulated utilities that are able to build their own capacity and earn a regulated rate of return. In those regions, the utilities don't need to compete for customers and can charge resource adequacy costs directly to end-use customers. However, independent generators must compete for resource adequacy buyers, leading to lower RA prices and few merchant builds outside of long-term utility contracts.

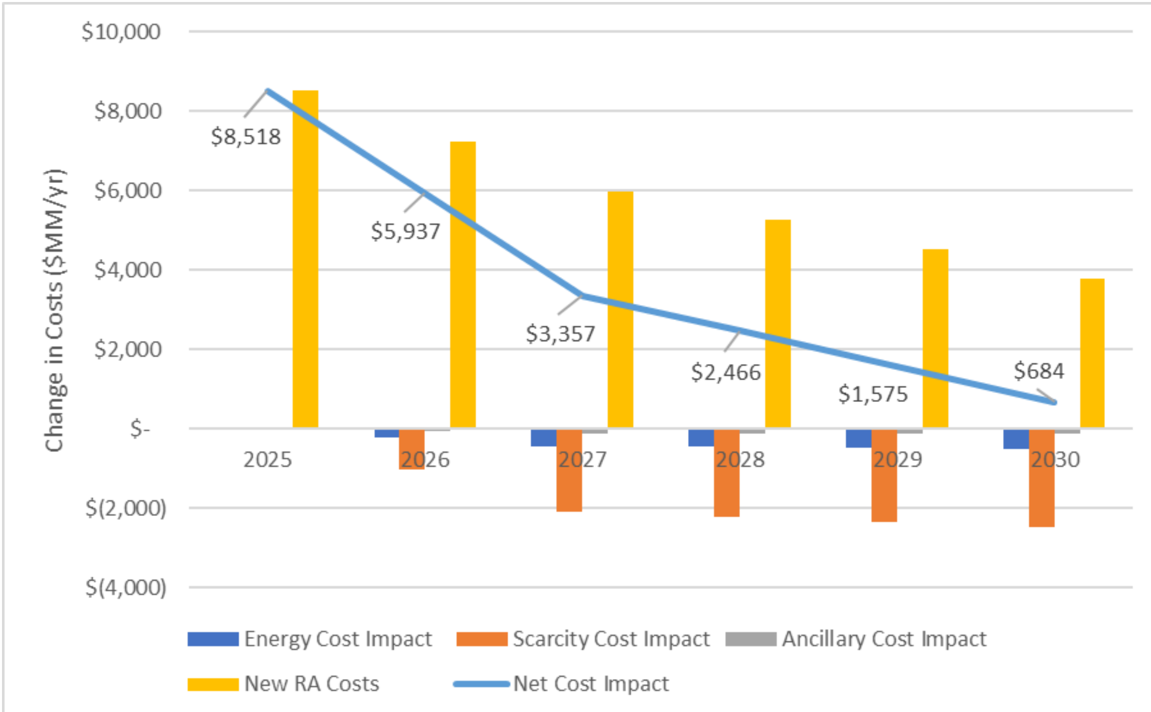
In contrast, the ERCOT wholesale market is more deregulated and decentralized compared to these other RA markets, and its largest LSEs serve areas with retail load competition. This gives more power to generators as sellers of capacity as compared to other RA markets. As a result, if retail competition is to be preserved, average RA prices for all generators in the market would have to be significantly higher in ERCOT than they historically have been in SPP, MISO, and CAISO to actually incentivize new builds.

This is demonstrated in CAISO, where resource adequacy prices are rising as reserve margins have dropped in recent years and retail load pseudo-competition has increased (via community choice aggregators). Another example is MISO zones 4 and 7, which allow limited retail competition, and have each experienced RA prices significantly higher than the rest of MISO. In ERCOT, which has extensive retail competition, these higher RA prices would affect payments to the entire market, including all existing suppliers. Therefore, total resource adequacy costs under the LSEO in ERCOT would be significantly higher than resource adequacy costs in other regions.

What level of pricing is needed to attract new generation? The current market structure already provides incentives for investors willing to take on significant merchant risks. To attract additional entrants with lower risk appetites, prices may have to rise to at least $5.50/kW-mo, approximately enough to cover fixed O&M plus debt service costs on a new gas simple cycle plant. One major limiting factor is that the LSEO (as outlined) has no mechanism incentivizing or locking-in RA payments for more than one year. Since most ERCOT load-serving entities serve in competitive retail markets with customer contracts no than 1-2 years in length, LSEs may be reluctant to sign long-term guaranteed RA contracts, because they cannot predict their future load obligations and have few contracted payment streams for 3+ years in the future. Smaller LSEs also have much less financial wherewithal to contract for the long-term. Therefore, RA prices may need to be higher than $5.50/kW-mo, perhaps as high as $8.0/kW-mo, with reserve margins close to the enforced minimum, in the initial years to spur longer-term contracting against the threat of the very-high program price cap for any shortage. At the same time, however, retail electricity prices encourage cost-cutting in the short term, making it harder to justify contracts at higher RA prices.

Figure 19 shows the cost impact of ICF's base LSEO resource accreditation method. In this case, reserve margins in the first implementation year (2025) are very near the target minimum, leading to RA prices of approximately $8.0/kW-mo to generation owners. This could spur 2 GW of additional incremental new gas builds by 2027, improving reserve margins by around 2% and leading to RA prices of $5.50/kW-yr. The new builds reduce scarcity price formation, offsetting some of the RA program cost. By 2030, RA prices drop further to $3.40/kW-yr as the market returns to an equilibrium situation, at approximately 2% higher RM than in Phase 1, where scarcity plus RA payments are sufficient to incentivize new generation. This scenario would increase total market costs by 36% in 2025 and about 16% on average over 2025-2030 over current Phase 1 market total costs.

Figure 19: LSEO cost impact relative to Phase 1 measures would be very high initially and drop over time (ICF resource accreditation case)



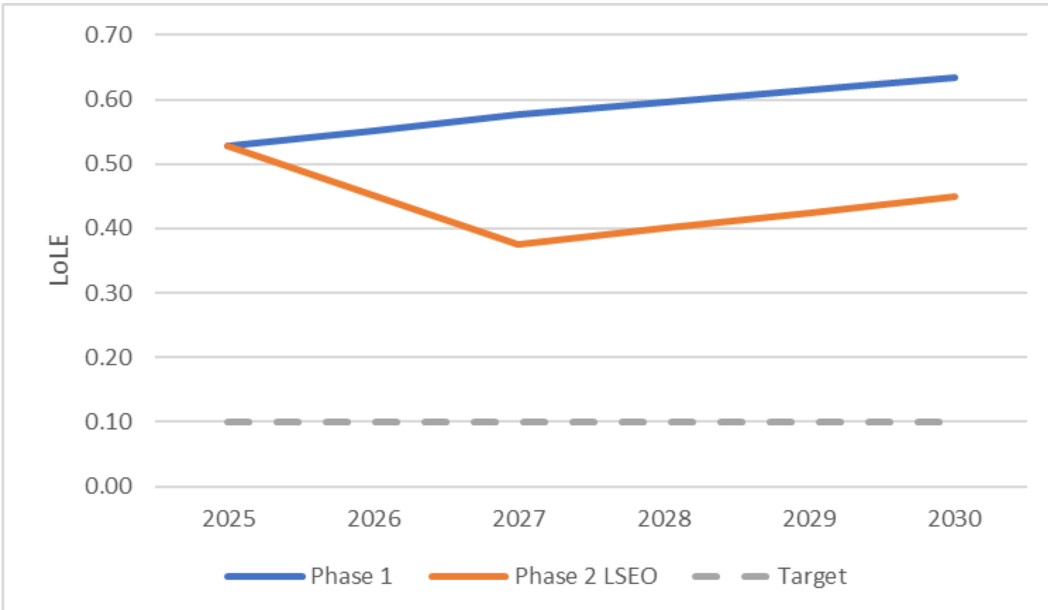
Under the LSEO, both scarcity and RA costs would increase greatly under a resource shortage, giving generators multiple, redundant payments for the same capacity. Well-designed RA programs require must-offer and performance obligations in exchange for RA payments to prevent withholding and assure that the resources actually operate when needed, or else the RA payment is simply free money without any assurance of performance. ERCOT's use of ORDC and high energy price bid caps are both meant to incentivize availability economically, without need for contracts and performance obligations; thus, the ORDC and LSEO programs would pay twice for the same resource behavior. Other RA markets have cost-verification for RA bids and cost caps of $1,000-2,000/MWh rather than ERCOT's $5,000/MWh. Eliminating the ORDC and making the LSEO the primary mechanism for incentivizing reliability could help reduce the risk of cost explosions under extreme shortage conditions, in lieu of using both programs simultaneously.

LSEO reliability impacts

As indicated above, ICF's analysis indicates that the LSEO option will not produce significant levels of new generation above that expected under current Phase 1 rules. Further, the LSEO will not produce significant reliability improvements according to the reserve margin, LoLE or EUE metrics regardless of which accreditation method is used.

Figure 20 below shows Loss of Load Expectation between 2025 and 2030 compared to Phase 1 for the ICF base resource accreditation methodology. Alternate methodologies could yield differing levels of builds, and therefore reliability impacts, in addition to differing costs. Greater reliability gains would occur if the LSEO resource adequacy payment, plus the energy and ancillary services payments, attracted more new generation at the same price levels as forecasted above. However, this appears unlikely because the LSEO provides only short-term (three year ahead) payments and does not give additional incentives for long-term contracting that might attract more risk-averse capital.

Figure 20: Phase 2 LSEO not likely to meet ERCOT target LoLE levels



Any LSEO program implementation should use a resource accreditation method that reflects ERCOT's future operational needs. For example, if resource accreditation is based primarily on expected output at peak demand, then it implies that ERCOT's primary challenge is meeting peak demand. ICF analysis indicates that the primary challenges today relate to meeting *net* peak demand (demand minus wind and solar generation), managing the grid during shoulder months when many generators and transmission lines are undergoing maintenance, and handling extreme weather situations including extreme load. ELCC methodologies that consider all hours and seasons of the year under reasonable forward-looking weather scenarios would better capture the range of risks the grid faces and various resources' ability to mitigate these risks.[19]

This analysis finds that by 2027-2030, ERCOT will face much higher loss of load risk in winter than in summer despite the winter weatherization improvements already undertaken in Phase 1, due in part to the increasing levels of solar and storage in the ERCOT resource fleet. Although ICF's case still focuses on summer reserve margins (which are lower than winter reserve margins), the minimum planning reserve margin for winter should be higher than that in summer due to the magnitude of potential load increases in extreme weather and the potentially deadly consequences of grid failures in winter. Resource accreditation levels also differ between summer and winter, especially for renewables. Therefore, seasonal distinctions in reliability requirements would better serve actual grid needs than an annual construct, which would likely focus on summer peak demand alone.

[19] Most ELCC methods are superior to the simplistic methodologies now used for the ERCOT CDR.

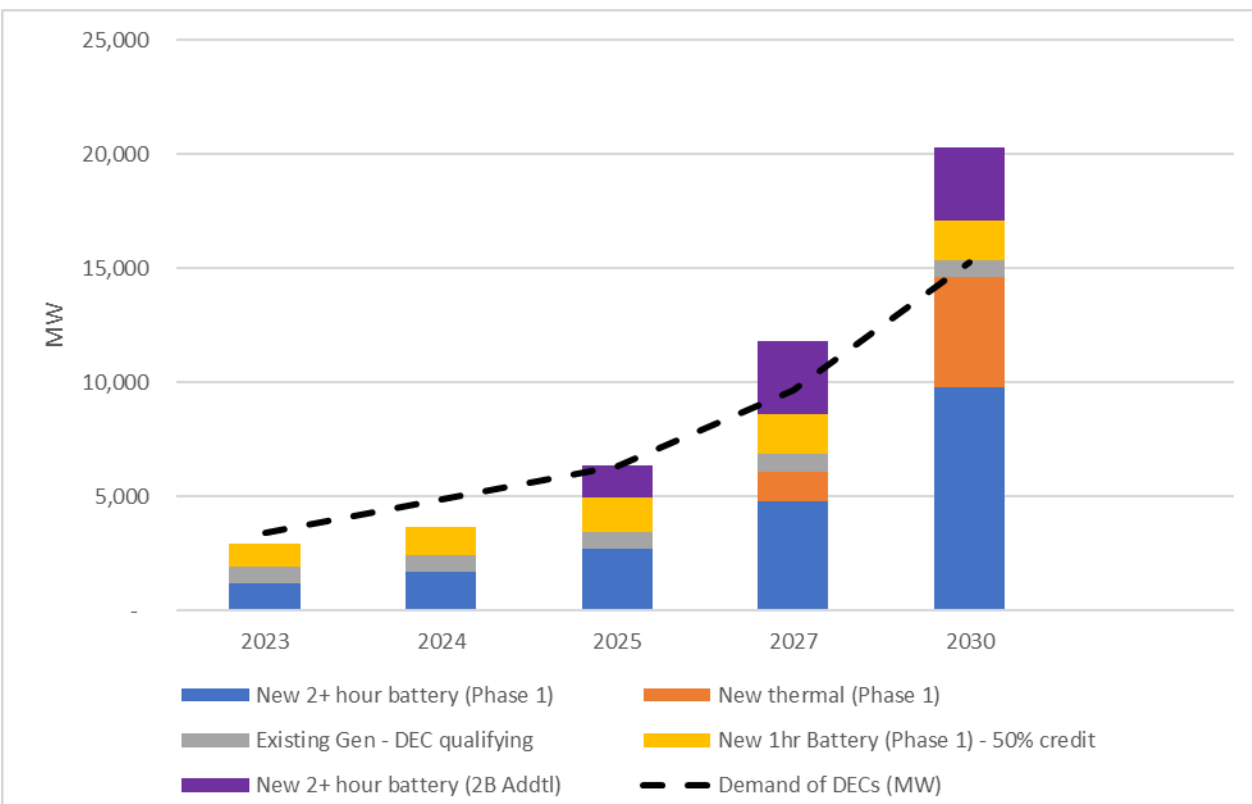
ICF's analysis above assumes that the LSEO primarily incentivizes new gas peaker plants; this is consistent with a stated desire for new dispatchable thermal generation. However, depending on how the accreditation is done and the reliability standard applied, batteries or solar could become LSEO beneficiaries rather than gas plants. Since all resources have very different operational characteristics that affect overall portfolio capability and cost, the resource accreditation analysis must be designed to recognize and meet the grid's primary stresses and needs, which may or may not be best served by new thermal.

3.4 Phase 2 – DEC

The DEC is the most well-defined Phase 2 proposal and is based on the concept of Renewable Energy Credits. The proposal would mandate that retail LSEs procure a specified amount of dispatchable energy credits (DECs) every year or pay a shortage price. DECs would be granted to each MWh produced by 2-hr batteries and highly efficient, quick-start thermal resources that produce according to specified fast-start, fast-ramp conditions. Administratively determined assignment of DEC purchase and retirement obligations would be indexed to each load-serving entity's share of retail load.

Program qualification, demand levels, and penalty/shortage prices are specified in the DEC proposal, allowing more precise impact analysis. In contrast to the LSEO, which focuses on systemwide capacity, the DEC program is designed to incentivize a narrow set of highly flexible, quick-start resources and is intended to improve the grid's flexibility and responsiveness to short-duration needs. DEC demand and forecasted supply in ICF's analysis are shown in Figure 21 below.

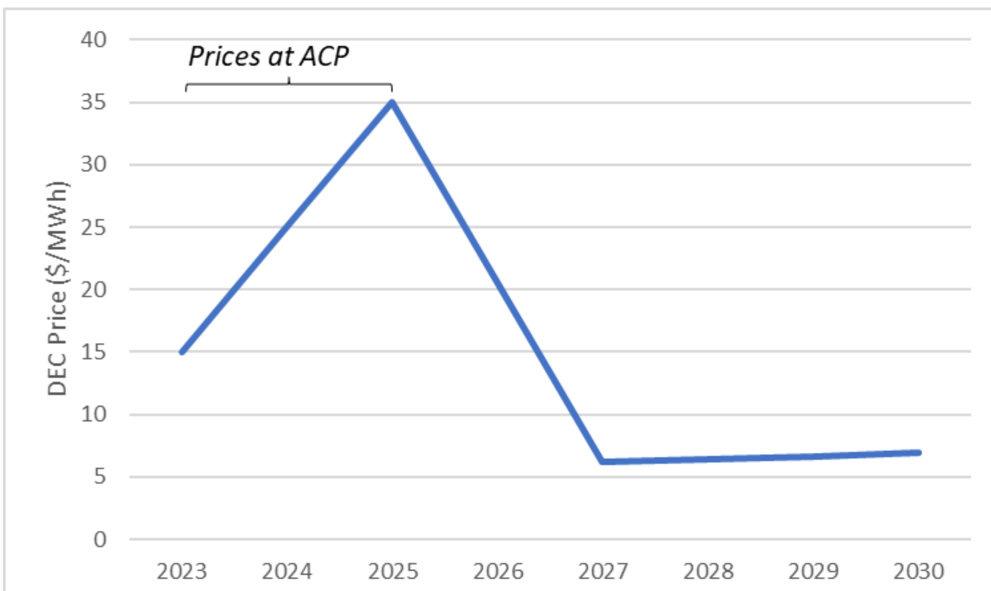
Figure 21: DEC policy would primarily incent new 2-hr storage



ICF assumed that under the DEC, all new one-hour batteries would self-limit[20] to deliver two hours of energy at half power in order to qualify for valuable DECs.

The buildout forecasted under Phase 1 leaves a shortage of DECs. ICF forecasts that by 2025, an additional 1.4 GW of 2-hr batteries could be built to fill the DEC gap, but the program would still clear at the price cap (alternative compliance payment (ACP)) because the load-serving entities that can't buy enough DECs would be indifferent between buying DECs and paying the alternative compliance payment. The DEC program is designed with an increasing ACP over time, starting at $15/MWh in 2023 and increasing by $10/MWh thereafter (i.e., up to $35/MWh in 2025). In 2027, we forecast that the DEC program will become over-supplied, with supply competition for DECs that push DEC prices down. The DEC price converges to the equilibrium returns of new 2-hr batteries against the other revenues they earn in the market against growing DEC demand. By 2030, there would be a modest excess of DECs and a moderate DEC price. Figure 22 shows the average forecasted DEC price through 2030.

Figure 22: DEC price forecast is high in initial years before dropping

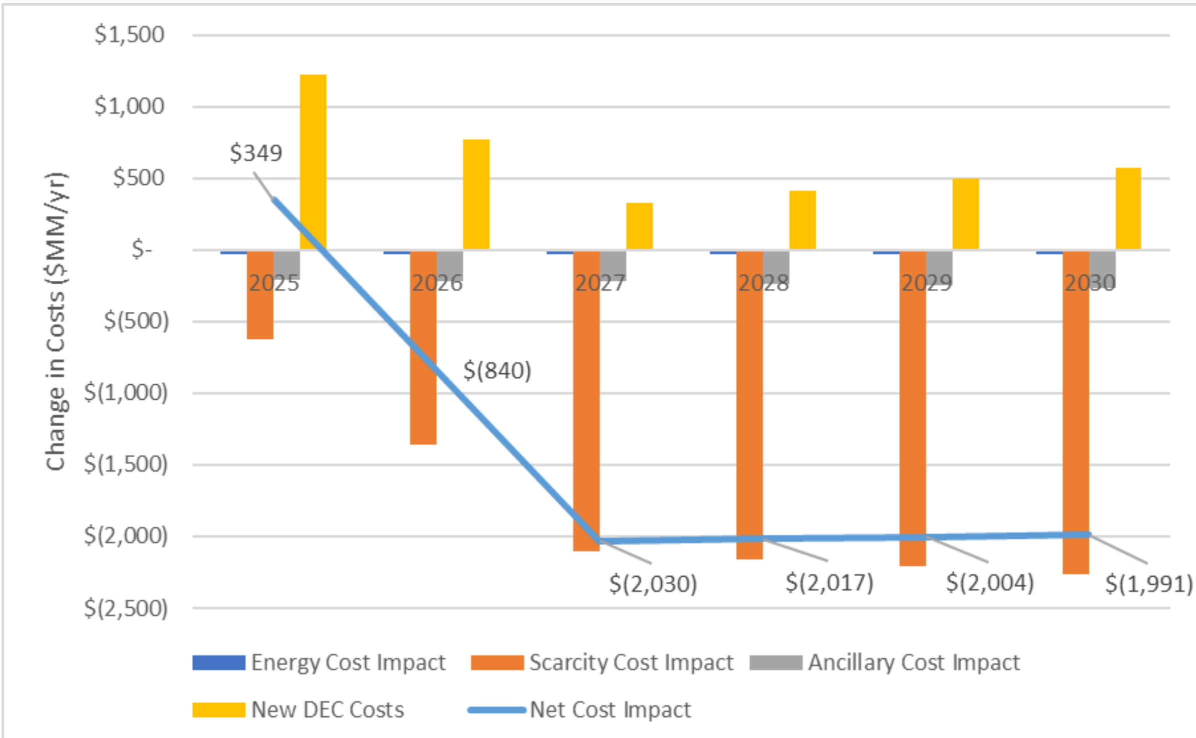


In addition to the new 2-hr batteries, the analysis also assumes all new thermal that was already forecasted to come online over 2025-2030 in Phase 1 would have to be DEC-qualifying (which requires the most advanced technologies and therefore is not a certainty); the long-term DEC price would need to cover the cost gap compared to cheaper, non-qualifying technologies such as frame CTs or older aeroderivative gas turbines.

[20] ERCOT has developed rules related to self-limiting resources, especially as related to battery storage

DEC Cost Impact

Figure 23: The DEC program would save money relative to Phase 1 market costs as overall scarcity costs fall

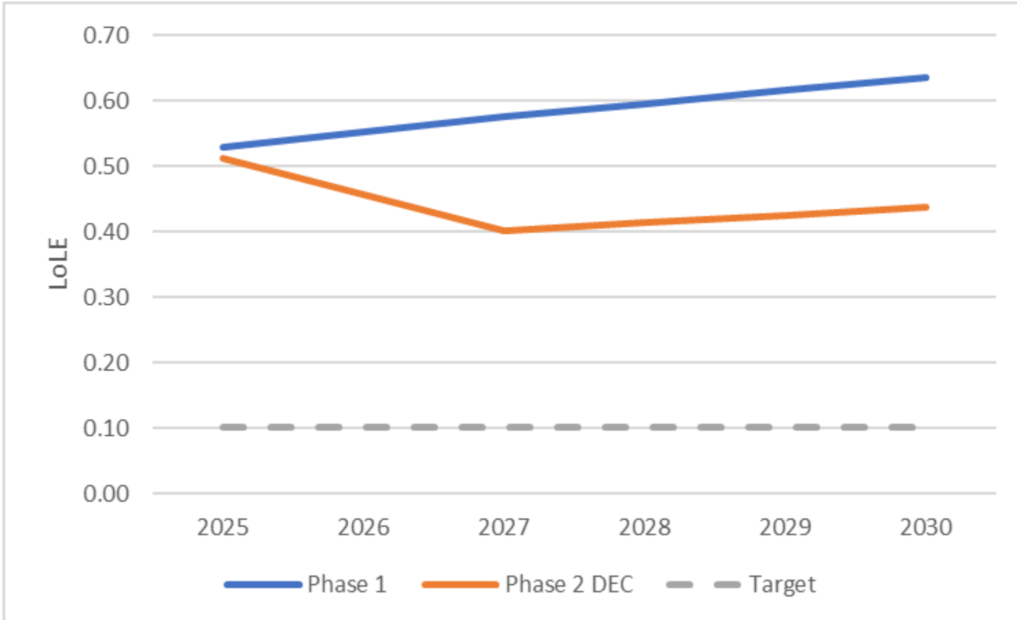


Total ERCOT system costs are expected to fall by 4%, on average, over 2023-2030 under the DEC. This is because the DEC creates additional payments (cost to market) to a small, limited set of new resources – most of which would be new builds – but those units would reduce energy, scarcity and ancillary service prices and costs across the entire ERCOT system. These cost reductions come mainly from lower scarcity prices compared to Phase 1, which reduce total payments for all energy produced across the ERCOT generation fleet. Therefore, the DEC program would have to be carefully balanced so as not to prompt additional retirements of older plants faster than it prompts new, efficient replacement capacity.

DEC Reliability Impact

The DEC program is projected to improve LoLE by around 30% by 2027 relative to Phase 1. If demand for DECs were increased faster, it could have a larger reliability impact by driving more new builds. However, because the DEC program is designed around a subset of system needs (specifically for more fast, flexible resources), it is not a complete solution to bring reliability up to target levels. As total battery capacity increases, the incremental effectiveness of 2-hr batteries starts to drop. This drop is because batteries are expected to smooth out peaks and short-term reliability risks but become less effective at covering long intra-day risks especially in winter. Reliability under DEC relative to Phase 1 is shown in Figure 24 below:

Figure 24: DEC improves reliability relative to Phase 1 but also falls short of achieving target



3.5 Phase 2 – BRS

The Backstop Reliability Service (BRS) is designed and modeled as a tool to prevent units that would otherwise retire from actually going offline, by paying each unit's going-forward fixed and operational costs to enable them to remain available and functional in case of emergency. Every unit that goes into the BRS program is assumed to be allowed and expected to operate only under emergency conditions and is prevented from operating in the day-to-day ERCOT energy market. Additionally, by program design, wholesale spot market prices should be unaffected by BRS-unit dispatch during system emergencies. Therefore, with a BRS program ERCOT energy market prices should be identical to prices prevailing in a case where the units retire.

This BRS framing contrasts to other backstop service designs, including one that removes existing units economically from the market to create "artificial scarcity" and an alternative that would grant state contracts to firms such as Berkshire or Starwood to build new units to be used solely for emergencies without any opportunity to compete in the energy market. The BRS program evaluated herein does not provide incentives to any new generation.

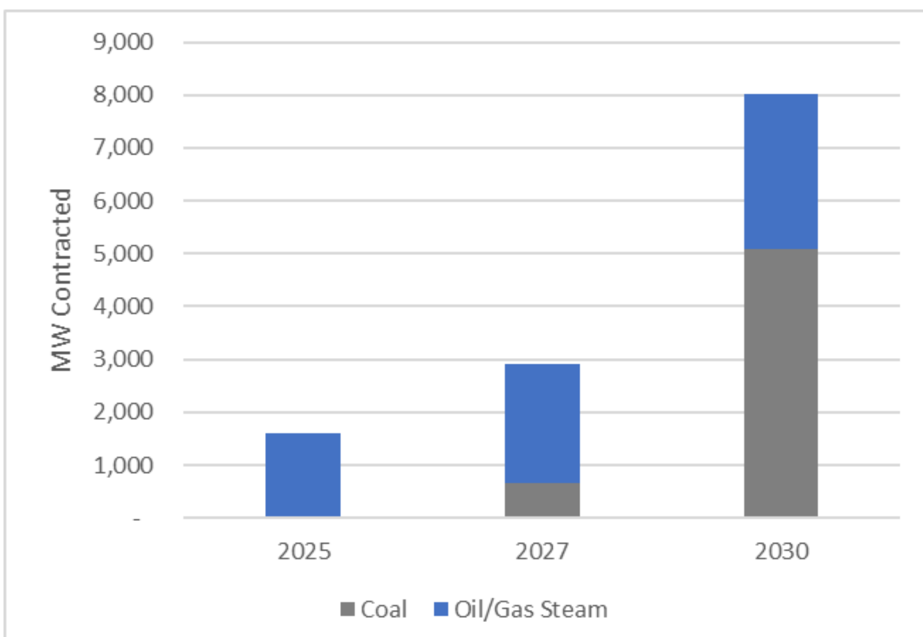
All capacity that is otherwise forecasted to retire under Phase 1 is modeled as BRS resources in this scenario. This capacity is mainly oil/gas steam units in 2025-2027, with several coal units entering the program over 2027-2030. In the Phase 1 analysis, these units retire because their higher fixed costs and fuel costs become less competitive over time in an environment increasingly dominated by lower-cost solar, wind, and storage resources.

One major concern with a BRS framework is that it could prompt more generators to declare retirement in order to secure guaranteed BRS funding (rather than continuing to compete in the energy market for uncertain future prices and revenues). Each plant would have to go through a cost-verification process that can be contentious (as seen, for example, in contests over nuclear unit subsidies in Illinois, New York and New Jersey in recent years). From a high-level system cost perspective, the outcomes of these negotiations matter relatively little, especially compared to the potential cost impacts of other Phase 2 proposals, but ensuring proper cost verification can help prevent perverse economic incentives. The BRS proposal only works if BRS contracts make their owners truly indifferent as to whether the plants fully retire or stay online under BRS.

Another potential challenge is the level of initial and ongoing capital investment needed to keep old fossil plants online. ICF has assumed life-extension capex requirements around $200-250/kW (see details in chapter 4) for all BRS capacity. However, some plants may be technically unable to continue operating without significant rebuild or new equipment. Additionally, it will be increasingly difficult to assume coal availability at moderate costs as the total amount of coal delivered to ERCOT falls over time. If some plant lives cannot be extended, BRS program costs and reliability impacts would both be reduced.

Figure 25 shows the amount of dispatchable thermal capacity assumed to move from energy market competition into BRS status (In lieu of full retirement). We assume (perhaps optimistically) that the plants that move into BRS status will retire at the same times that they would have retired under Phase 1 rules (i.e., without the BRS program incentives) and would not accelerate the plants' retirement timing. We also assume that if the PUCT chose to adopt the BRS program, it would also adopt some competitive mechanism to select the lowest cost resources to enter into multi-year BRS contracts, that there would be strict performance obligations placed upon BRS units to assure that they show up when emergency needs require, and that there would be some outer limit on how long an individual resource could remain in the BRS program.

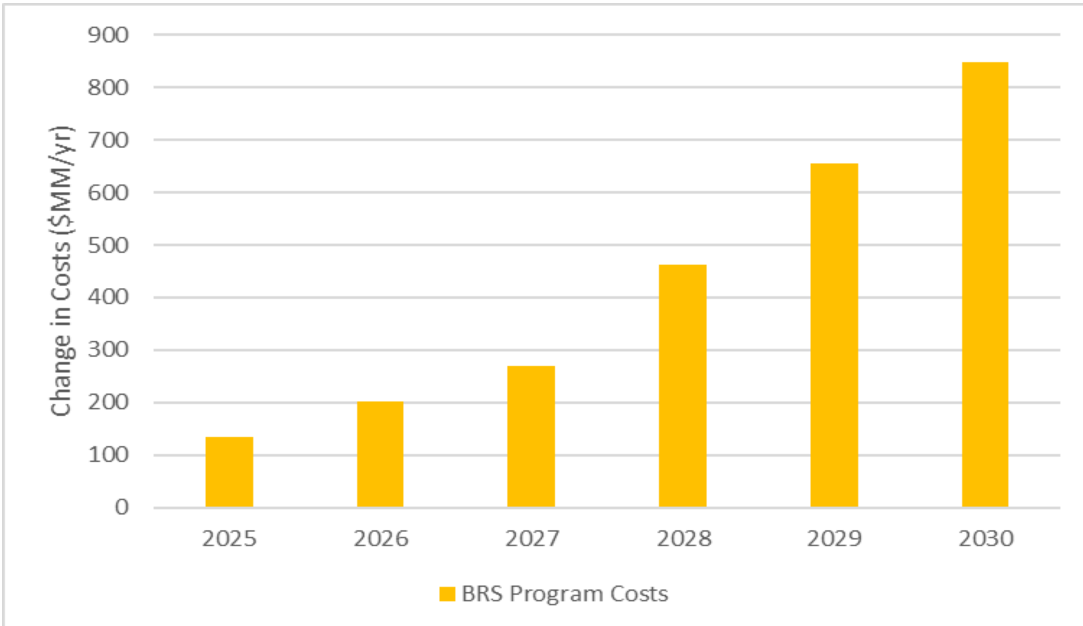
Figure 25: Capacity contracted under the BRS grows over time



BRS Cost Impact

Because BRS-contracted units are economically removed from the market, the only cost impact of the program is the direct payments to the BRS generators. The BRS program should have no impact on energy, scarcity, or ancillary prices. BRS program costs will grow as capacity in the program grows, as shown in Figure 26. Fixed and operating costs for the BRS units total approximately $85-100/kW-yr, including assumed capex requirements to keep aging units online. Total incremental BRS costs over 2025-2030 are about $2.6 billion, or about a 2% increase in total system costs over the period.

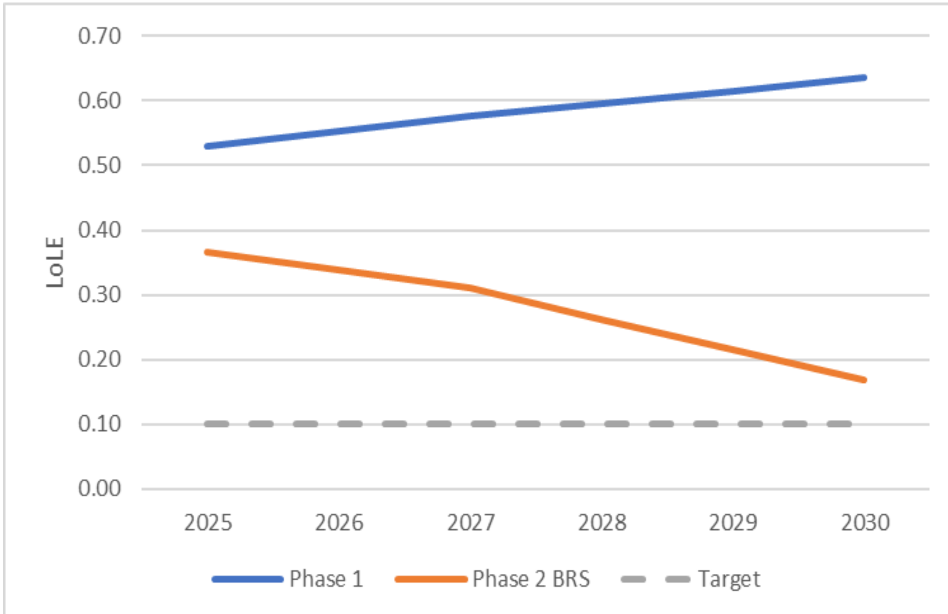
Figure 26: BRS costs (relative to Phase 1 totals) grow over time as capacity in the program increases



BRS Reliability Impact

The BRS program appears to offer the largest reliability benefit of all the Phase 2 policy options modeled because it would deliver the largest volume of additional MW for emergency operations. By 2030, while the LSEO would incentivize 2.5 GW of new gas and the DEC would incentivize 3.2 GW of 2hr battery, the BRS preserves 8.0 GW of capacity from retiring – on top of the new capacity realized from the Phase 1 rules. The BRS would improve LOLE in 2030 to 0.17 (Figure 27), the best of the Phase 2 proposals but still just above target minimum reliability levels.

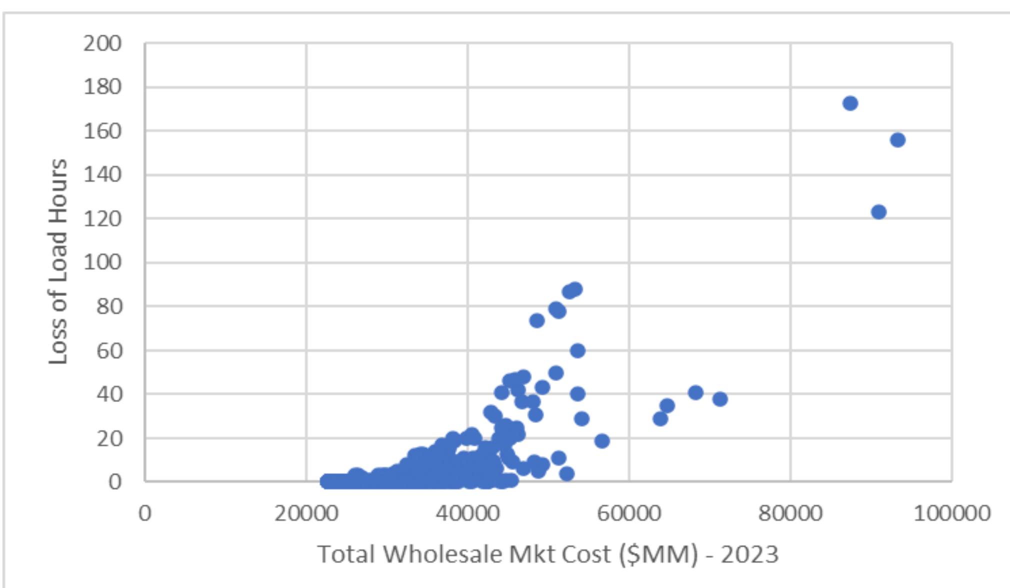
Figure 27: BRS achieves significant reliability improvements compared to Phase 1



3.6 Stochastic Analysis Findings

As noted in Section 1, this analysis examines the effectiveness of each policy scenario by analyzing its performance against a consistent set of 1,000 different weather, load forecast error and generator outage conditions. To illustrate this process, Figure 28 shows the results of these 1,000 different cases for 2023 total costs relative to loss of load hours (LoLE) under the Phase 1 scenario. All of the individual 1,000 case results are then rolled up into a single average number that is used in the policy scenario assessments herein.

Figure 28: Scatterplot of total market cost ($MM) vs loss-of-load hours for all 1,000 simulations for Phase 1 in 2023

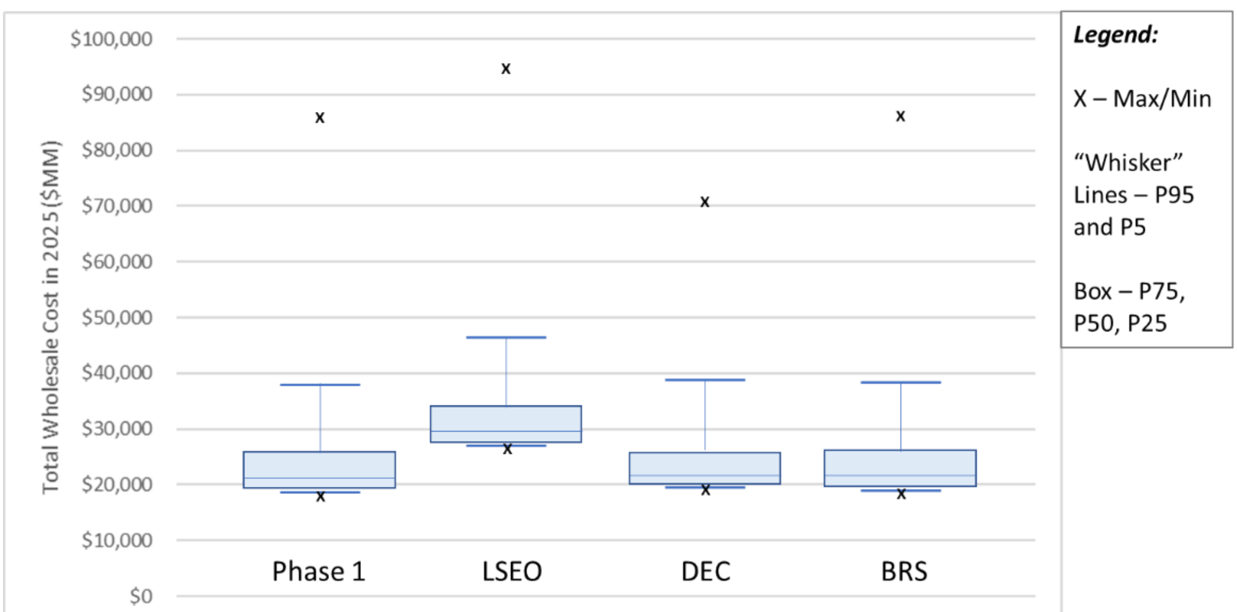


However, a simple arithmetic average does not convey the full breadth of variations and risks created under each policy. In every forecast year, there is a wide range of cost outcomes due to uncertainty in weather, renewable output, and unit forced outages. It is also useful to consider the range of outcomes relative to the average outcome to identify low-probability but large-impact risks that might occur due to extreme weather conditions or other factors.[21]

Figure 29 illustrates this by showing the full range of statistical outcomes. The x-points denote the maximum and minimum values, the "boxes" show the P75, P50, and P25 outcomes (i.e., typical years), and "whiskers" denote the P5 and P95 (i.e., unusual but not extreme) outcomes for the total wholesale costs of the four policy alternatives in 2025. The worst 1-2% of outcomes show very high costs, as if another severe winter storm occurred. While Phase 1 reforms would make a repeat of Uri less disastrous than the 2021 actual outcome, it would still cause very high costs and likely outages.

All policy options were analyzed under an identical set of simulated weather risks and generator outage conditions. The LSEO shows higher costs in the first year of implementation than other policy options since it would impose a larger additional cost stream on the market. The LSEO costs shown in Figure 29 use the ICF base case resource accreditation method.

Figure 29: High range of total system costs in 2025 for all four policy scenarios, but LSEO costs higher than other scenarios



Under worst-case scenarios, LSEO implementation could impose high resource adequacy costs on top of resource shortages and high energy costs, reflecting the duplicative nature of resource adequacy payments

[21] The analysis includes variability with respect to: peak and total load (forecast errors vs expected levels), thermal unit maintenance and forced outages, and wind and solar output. Other variables that could affect wholesale costs include fuel prices and fundamental changes in supply/demand from the forecasted cases.

and scarcity pricing. Figure 30 shows the range of costs for all scenarios including implementation uncertainty in the LSEO. The range of costs shown is based on an equal probabilities of each of the seven resource accreditation scenarios analyzed in chapter 3.3, plus the fundamental range of market costs outside of resource adequacy payments.

Figure 30: LSEO cost variability in 2025 increases significantly given uncertain program implementation

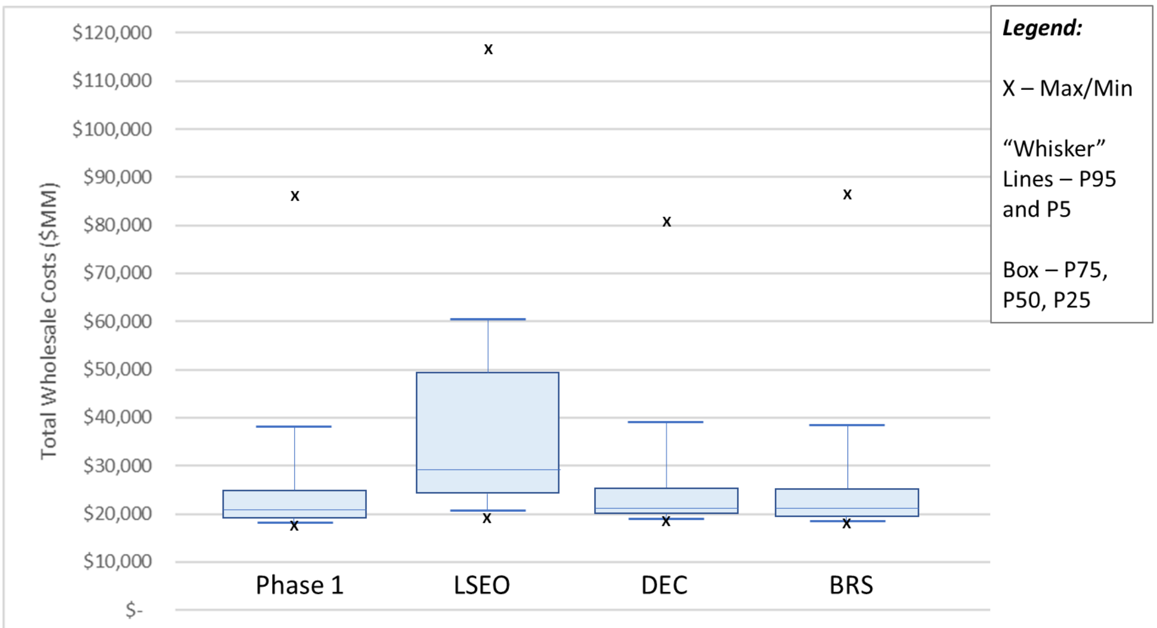
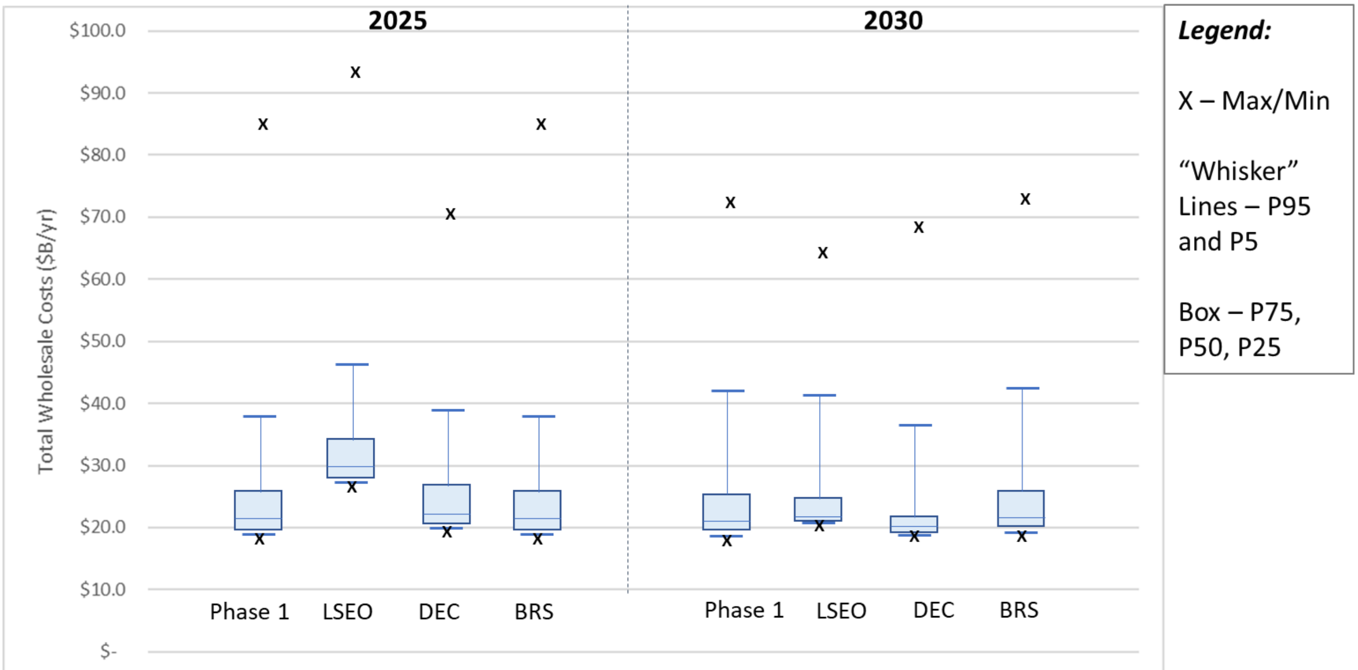


Figure 31 compares cost variability in 2025 and 2030 across Phase 1 and the three Phase 2 scenarios. By 2030, the range of wholesale costs drops slightly compared to 2025 under the LSEO (using the ICF Base Case resource accreditation method and buildout forecast) and DEC. This is due to the incremental generation brought online by the LSEO and DEC compared to Phase 1. The BRS keeps additional generation online compared to Phase 1, but by design it does not impact spot market prices.

Figure 31: Cost variability decreases by 2030 under LSEO and DEC



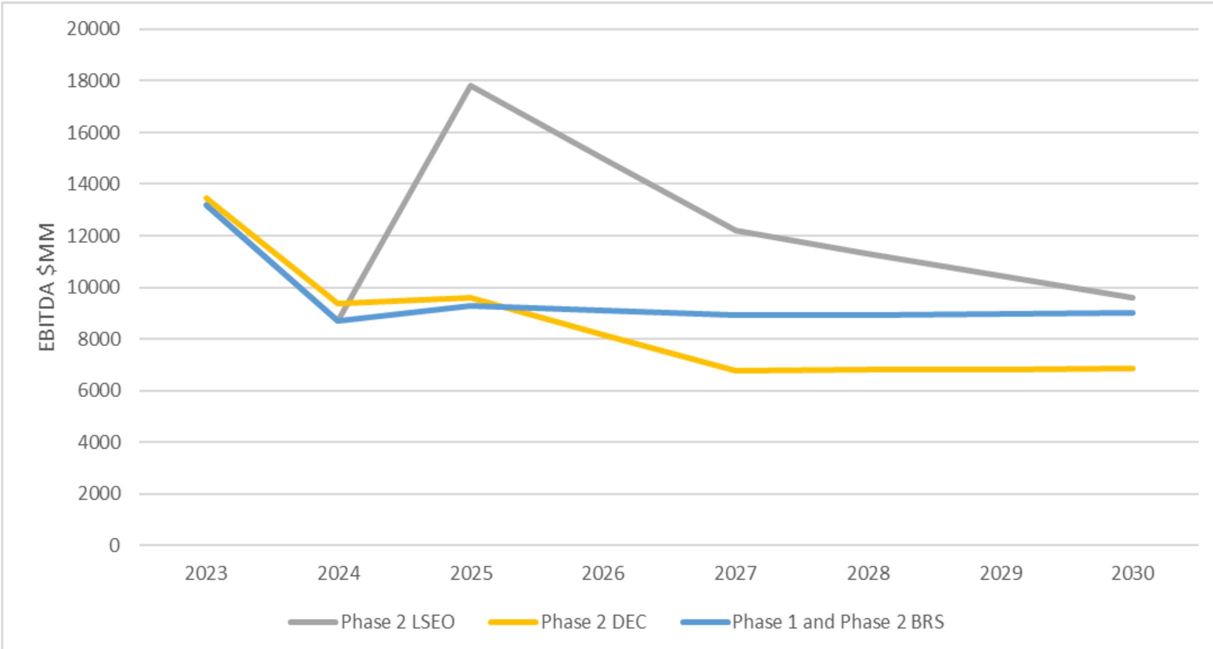
3.7 Impact on Generator Earnings

ICF compared total approximate generators' EBITDA[22] across the market in all scenarios to determine the impacts of these policy options upon generators' bottom lines. EBITDA was calculated as the sum of market payments (energy, scarcity, ancillary, and program payments) times output volume, minus all variable operating costs and fixed operations and maintenance costs (FOM). FOM values used are shown in the technical appendix.

Generators will earn the most under the LSEO case because it would give high resource adequacy payments to all resources as shown in Figure 32. Generators collectively will earn the least under the DEC case, because program payments are comparatively low, go to a limited number of targeted resources, and the new flexible resources drive down wholesale energy market prices. Earnings under the BRS case are identical to Phase 1 because the operating costs of BRS units are paid through the program, without excess earnings payments to either BRS or other generators.

[22] Earnings Before Interest, Taxes, Depreciation, and Amortization

Figure 32: Estimated total EBITDA earned by generators is highest under LSEO and lowest under DEC



3.8 ICF Policy Recommendations

If the PUCT continues to explore these Phase 2 policy options, ICF offers the following limited recommendations to improve each Phase 2 policy option based on this analysis:

LSEO:

- A phased-implementation approach should be used to reduce price shock in the first year of the program. Several ways of achieving this could be:
  - Consider ramping up reliability targets over the first 1-2 implementation years rather than a full standard in the first year
  - Use a low resource adequacy price cap (e.g., 0.5x CONE) for the first 1-2 implementation years
  - Use a look-ahead period longer than 3 years for the first study year
- Lower the ERCOT systemwide energy price cap from $5,000/MWh to $1,000 or $2,000/MWh, except for verifiable-cost bids
- Determine and publicize details as to how resource accreditation, reliability standards, and program cost caps will be determined before any further consideration or analysis of the program
- Resource adequacy penalty price should be 1.0x or 1.5x CONE rather than 2-3x CONE
- Resource accreditation should be based on defensible and unbiased ELCC methods using transparent modeling input assumptions
- If adopted, revisit and update ELCC methods and LSEO triggers over a predictable schedule to be sure that the LSEO is giving appropriate resource credits and tying payments to actual reliability needs as the grid evolves over time

- Implement strict performance standards for resource payments to tie consumer costs to actual reliability delivered by units being paid for resource adequacy
- Ensure that LSEs can use demand response, distributed energy resources and energy efficiency options to earn resource adequacy credits based on their demonstrated reliability value to the grid
- Recognizing that resource adequacy is one aspect of overall grid reliability, consider complementary programs or incentives, such as incentivizing flexibility and ramping (e.g., through DEC or other programs) to address other grid needs.

DEC:

- Index the demand for DECs to metrics that tie directly to the grid's relative need for flexibility rather than a generally increasing demand assumption tied to load
- Consider basing the requirement to qualify for DECs on fundamental characteristics tied to flexibility (e.g., ability to ramp at specified rates) rather than characteristics such as heat rate or battery duration that do not directly relate to flexibility
- Consider ways to mitigate the potential for the program to hasten retirement for existing generators that do not qualify for DECs, such as pairing the DEC with the BRS

BRS:

- Consider ways to limit incentives for early retirement:
    - Include claw-back mechanisms for revenues earned in excess of costs
    - Include in the program all best practices for tying payments directly to verifiable and necessary resource costs
- Set a hard limit on the size of the program (either in terms of dollars, MW, program duration, or all of the above)
- Ensure that the impact of BRS-unit generation and availability is fully removed from all energy and ancillary markets
- Since potential BRS units may have limited operational flexibility, plan BRS dispatch to maximize the units' reliability benefit. For example, it may be most beneficial to run BRS units at full load on high-risk days, freeing up more-flexible units to remain in standby or operate in a load-following pattern rather than asking BRS units to operate in this manner. However, this must be done carefully to ensure that economic outcomes for all parties are as if the BRS units were retired.

4 Technical Appendix

4.1 Modeling Approach and Model Descriptions

ICF employed four primary modeling platforms in this analysis:

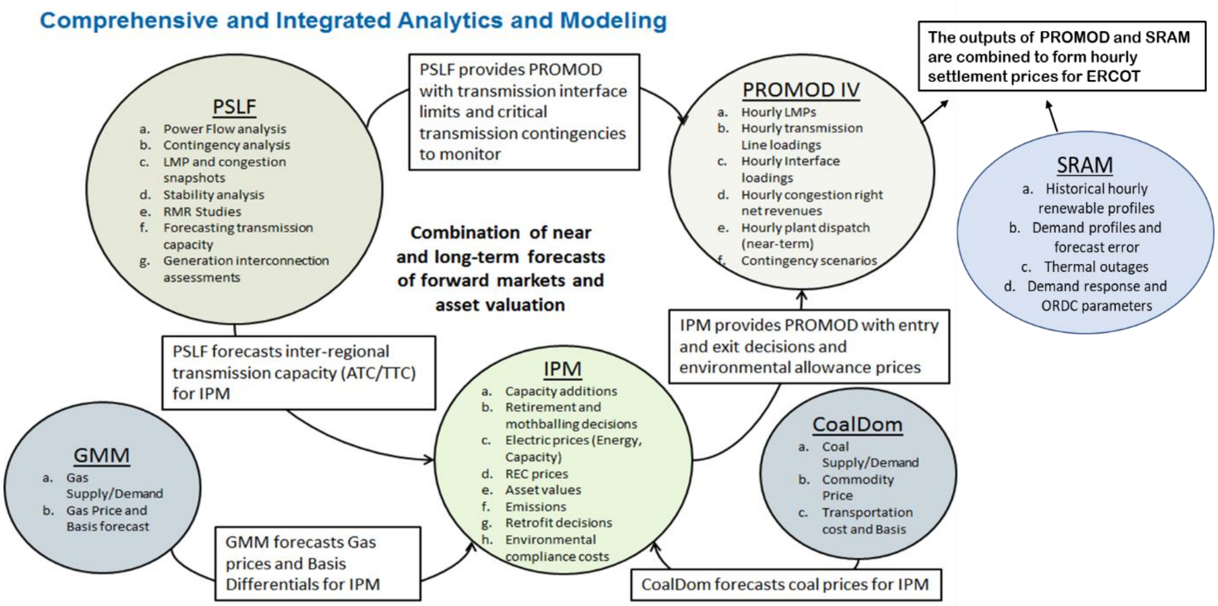
1. **ABB's PROMOD** – a nodal, hourly SCED model. This was used to project energy (LMP) prices and unit variable costs. Outputs of PROMOD are also fed into the ancillary price model.
2. **ICF's proprietary SRAM** – a probabilistic loss-of-load style model utilizing a Monte Carlo approach to simulate hourly operating reserves. This was used to project scarcity costs and loss-of-load metrics, and outputs also fed into the ancillary price model.
3. **ICF's proprietary ancillary service model** – utilizes inputs from PROMOD (unit commitment, energy prices) and SRAM (scarcity prices) to forecast ancillary service commitment and pricing.
4. **Program-specific models for Phase 2** – bespoke analysis to forecast cost impacts of the various Phase 2 proposals.

Secondary models that were not directly employed in this analysis but informed the starting point for the Phase 1 forecast, are listed below. The forecast for Phase 1 corresponds to ICF's Base Case, utilized widely in ICF's consulting, as of 7/28/22.

1. **ICF's proprietary GMM** – a production-cost model focused on the natural gas sector. GMM forecasts long-term monthly gas prices at over 100 hub points across North America.
2. **GE PSLF** – an AC load flow model used to identify transmission constraints as an input to PROMOD.
3. **ICF's proprietary IPM** – a production-cost model focused on the power sector. IPM is used to forecast economic new entries and retirements associated with the Base Case as inputs to PROMOD.

The schematic below shows the interrelationships between ICF's core models.

Figure 33: Interrelationships between ICF's core models



4.2 Input Assumptions

PROMOD

A summary of major inputs to PROMOD and are listed below along with their derivation:

Table 2 – Summary of major inputs to PROMOD

	Parameter	2023	2024	2025	2027	2030
Fuel Costs ($/MMBtu)	Henry Hub Gas	5.34	4.61	4.43	3.73	3.84
	Katy	5.42	4.68	4.53	3.69	3.70
	HSC	5.44	4.68	4.53	3.86	3.98
	NGPL - South Texas	5.49	4.81	4.67	3.65	3.67
	El Paso Permian	4.20	4.11	4.07	3.29	3.28
Projected Cumulative Additions (GW)	Gas	1.7	1.7	2.4	3.4	6.6
	Wind	2.1	3.7	5.5	5.5	5.5
	Solar	3.5	7.5	11.5	15.6	20.8
	Storage	3.0	3.9	5.4	8.0	13.0
	Total Builds	**10.3**	**16.8**	**24.8**	**32.5**	**45.9**
Projected Cumulative Retirements (GW)	Oil/Gas Steam	-	-	1.6	2.3	2.7
	Coal	-	-	-	0.6	5.1
	Nuclear	-	-	-		
	Total Retirements	**0**	**0**	**1.6**	- **2.9**	- **7.8**
Demand	Peak Demand (GW)	79.9	81.2	82.4	84.5	87.1
	Energy Demand (TWh)	440	452	460	477	496

Peak and energy demand: We used ERCOT's 2021 Long-Term Load Forecast.

Gas prices: ICF used forward market prices traded on ICE over the month of June 2022 for Henry Hub, Katy (ERCOT North), El Paso Permian (West), NGPL South TX (South), and Houston Ship Channel (Houston) for the forecast period 2023-2025. Gas prices from 2027 onwards reflect ICF's fundamental gas price outlook, with 2026 reflecting an interpolation from the futures prices to the ICF outlook.

New builds: The Base Case includes two categories of builds: firm and economic. Firm builds are based on advanced-stage projects meeting ERCOT's Planning Guide 6.9(1) and full interconnection study (FIS) criteria as of ERCOT's June 2022 GIS report. Planning Guide 6.9(1) requires a signed interconnection agreement and posting a letter of credit to the transmission provider for interconnection-related costs. Historically, plants meeting these criteria have had high success rates (~90%+). Over the long term, further new builds are projected based on economics using IPM.

Retirements: In the same manner as builds, ICF includes firm retirements based on announcements, and then economic retirements based on a discounted cash flow assessment of going-forward revenues and costs. ICF also assumes all plants retire after 67 years of operation, statistically the point at which less than 1% of capacity remains operational in the US.

This table shows the retiring plants and the reason for retirement, as reflected in the modeled resource base:

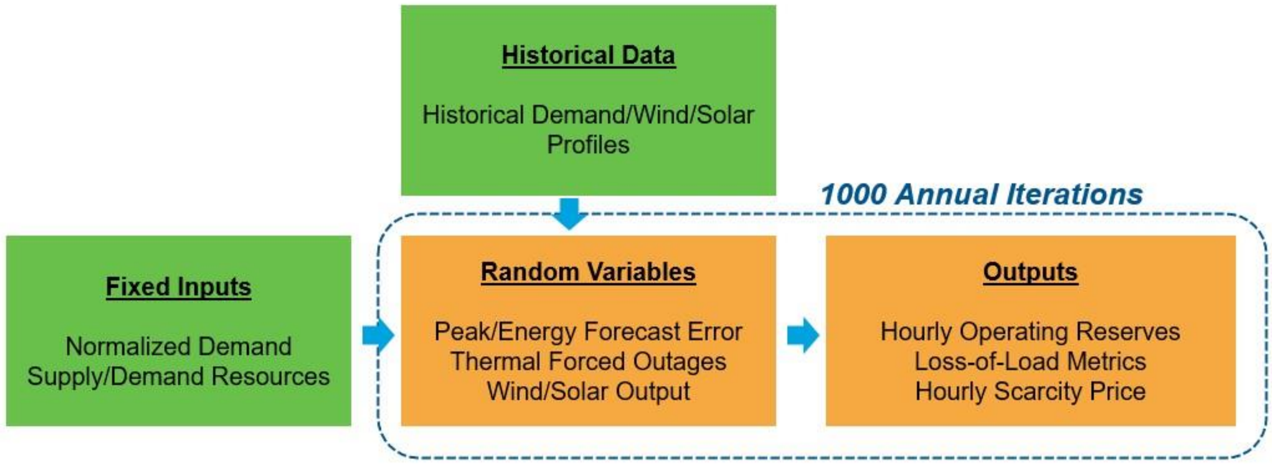
Table 3 – Retirements modeled in Phase 1

Fuel Type	Plant Name	Online Year	Retirement Reason	Retirement Year	Capacity (MW)
Coal	Coleto Creek	1980	Firm (Announced)	2027	655
	Martin Lake	1977-1979	Economic	2030	2410
	Fayette	1980-1992	Economic	2030	1640
	San Miguel	1982	Economic	2030	391
Gas	VH Braunig STG 1-3	1966	Firm (Announced)	2025	859
	OW Sommers STG 1	1978	Firm (Announced)	2027	420
	Mountain Creek STG 6-7	1956-1958	Age	2025	240
	Stryker Creek STG 1	1958	Age	2025	167
	WA Parish STG 1-2	1958	Age	2025	338
	Graham STG 1	1960	Age	2027	239
	WA Parish STG 3	1961	Age	2030	240
	Silas Ray STG 6	1962	Age	2030	20
	Handley STG 3	1963	Age	2030	395
			Total		**8,014**

SRAM

A schematic of SRAM's operation is shown below. SRAM utilizes a Monte Carlo approach to simulate hourly operating reserves across 1,000 iterations for each forecast year. We used SRAM to create 1,000 combinations of time-sequential weather conditions for the five forecast years (2023, 2024, 2025, 2027 and 2030) and then added on random thermal outage rates, renewable generation levels and demand forecast errors. Those sets of 1,000 cases for each of the five forecast years were then frozen and used to analyze all five policy scenarios (Phase 0, Phase 1, and Phase 2-LSEO, -DEC and -BRS) to assure consistent evaluation across the scenarios.

Figure 34 – Summary of SRAM model structure



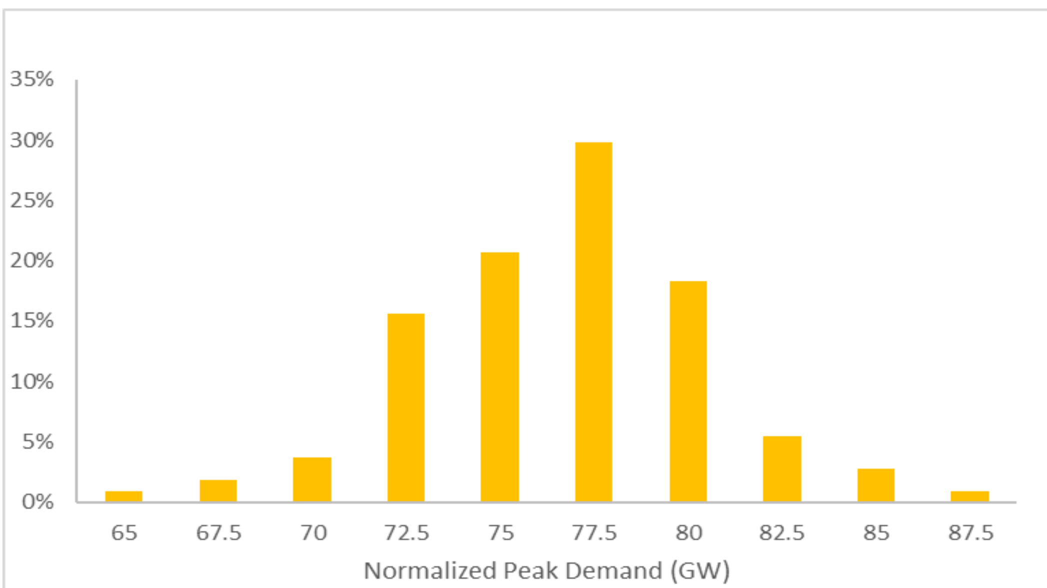
This table summarizes major inputs to SRAM and some key resource parameters.

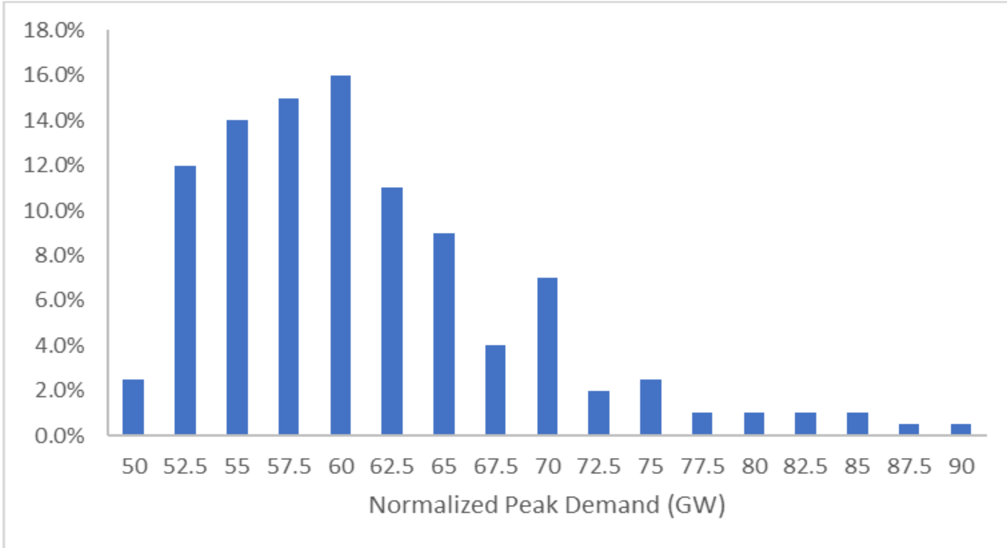
Table 4 – Summary of major inputs to SRAM

Parameter	Value / Source / Comment
Normalized Hourly Profiles – Wind and Solar Generation, ERCOT Demand	Demand: ERCOT historical hourly values 2008-2020 Wind and solar profiles taken from ERCOT's study of Hypothetical Profiles (1980-2020). Only 2008-2020 were used to correspond to demand profiles. The model used the same weather year for wind, solar, and demand in each iteration.
Demand Forecast Error	Lee, Jangho and Dessler, Andy, "The Impact of Neglecting Climate Change and Variability on ERCOT's Forecasts of Electricity Demand in Texas," *Weather, Climate, and Society* 14(2):499-505 ICF adapted the peak demand forecast error distributions for winter and summer shown on page 503. The discrete distributions are reproduced below. The simulated peak errors are applied to the top 5 load days in each season.
Generator Outage Rates	ICF started with NERC GADS data for individual plant forced outage rates. We then calibrated the fleet average outage rates to match ERCOT's SARA values for the 50th and 90th percentiles for each season (Fall 2021, Winter 2021-22, Spring 2022, Summer 2022 SARA reports) To simulate Phase 0 winter outage rates, we utilized average forced outage rates during Uri with a 0.5% chance of occurrence (also calibrated to historical weather frequency over 2011-2021); this variable was removed to simulate Phase 1 outages post weatherization. Outages rates are re-simulated every 88 hours in each model iteration, with interpolation

	in-between, this value also corresponds to the cutoff for statistically significant autocorrelation in fleet outage rates.
Battery Storage	Assumed to optimally dispatch during tightest operating hours as system approaches emergency. Assumed 1 cycle limitation per day.
Demand Response	ERS MW assumed to dispatch at the price cap (ERS will actually dispatch prior to EEA in Phase 1 but will be considered a reliability deployment event for pricing purposes) Price-responsive DR assumed to dispatch at stepwise at prices between $500-1,500/MWh
ORDC Parameters	$9,000/MWh price cap and 2,000 MW MCL (Phase 0) $5,000/MWh price cap and 3,000 MW MCL (Phase 1 and 2)

Figure 35: Peak Demand Forecast Error Distributions by Summer (top) and Winter (bottom) in SRAM





LSEO-Specific Assumptions

As explained in Chapter 3.3, ICF evaluated seven different cases for resource accreditation. The resource credit levels assumed are shown below. When sources used a single average (e.g., ERCOT with respect to thermal), ICF gave the same credit level to all types. In some cases, where data was missing, we adopted rates from other studies. For example, for the Astrapé-derived case, we adopted ERCOT values for other and hydro (these are small categories). In other cases, ICF interpreted the results; e.g. for the Astrapé-derived and ICF-UCAP cases, we utilized the weighted-average across gas technologies. Note that this assumption differs from SRAM, which utilizes individual asset outage rates by type and size.

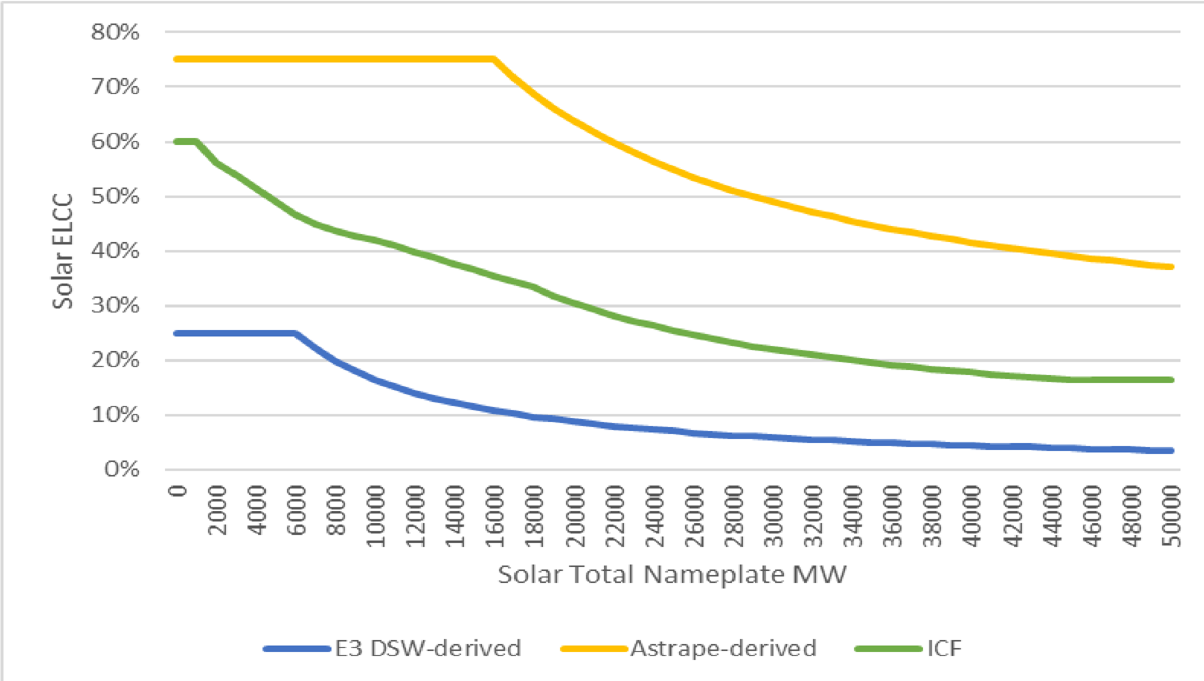
Please note: for the E3 DSW-derived and Astrapé-derived cases shown, the values utilized should be read as ICF's adaptation / interpretation of publicly-available information in the referenced reports. E3 and Astrapé were not involved in any way in this present study and did not provide data or input for this analysis.

Table 6 – Resource Credit levels assumed in the different cases ICF analyzed

Summer							
	E3 DSW-derived	**ERCOT SARA**	**ICF-UCAP**	**Astrapé derived**	**ERCOT CDR**	**ICF-ICAP**	**Last 12 Months**
Nuclear	97%	94%	98%	100%	100%	100%	98%
Coal	90%	94%	93%	94%	100%	100%	84%
Natural Gas	94%	94%	94%	93%	100%	100%	89%
Other	98%	94%	94%	94%	100%	100%	89%
Hydro	79%	83%	83%	83%	83%	83%	83%
1-hr Battery	23%	0%	35%	25%	0%	35%	35%
2-hr Battery	45%	0%	60%	50%	0%	60%	60%
4-hr Battery	90%	0%	90%	100%	0%	90%	90%
Solar	**	81%	**	**	81%	**	74%
Wind-Inland	33%	20%	12%	13%	20%	12%	27%
Wind-Panhandle	33%	30%	12%	22%	30%	12%	27%
Wind-Coastal	33%	57%	47%	37%	57%	47%	27%
Winter							
	E3 DSW derived	**ERCOT UCAP**	**ICF-UCAP**	**Astrapé derived**	**ERCOT ICAP**	**ICF ICAP**	**Last 12 Months**
Nuclear	97%	88%	98%	100%	100%	100%	**100%**
Coal	90%	88%	85%	94%	100%	100%	83%
Natural Gas	94%	88%	87%	93%	100%	100%	81%
Other	98%	88%	87%	88%	100%	100%	81%
Hydro	79%	73%	73%	73%	73%	73%	81%
1-hr Battery	23%	0%	35%	25%	0%	35%	35%
2-hr Battery	45%	0%	60%	50%	0%	60%	60%
4-hr Battery	90%	0%	90%	100%	0%	90%	90%
Solar	**	11%	**	**	11%	**	20%
Wind-Inland	33%	19%	12%	13%	19%	12%	41%
Wind-Panhandle	33%	34%	12%	22%	34%	12%	41%
Wind-Coastal	33%	46%	47%	37%	46%	47%	41%

For solar, ELCC drops as more capacity comes online. The ICF, Astrapé-derived, and E3 DSW-derived cases use a declining scale for solar as shown below:

Figure 36: Solar ELCCs applied by ICF in LSEO



DEC-Specific Assumptions

DEC volumes and ACP were taken directly from "PUCT Recommendation: Dispatchable Energy Credit Program" delivered on Nov 15, 2021.

BRS-Specific Assumptions

Costs applied to BRS-contracted generation are shown below. The values shown come from EPA's Power Sector Modeling Platform v6 for the respective technologies. ICF levelized the life extension capex over five years, assuming BRS would not be used on any given unit indefinitely.

Table 7 – Costs applied to BRS-contracted generation

Tech Type	FOM (2023$/kW-yr)	Life Extension Capex ($/kW)
Coal	48	240
Oil/Gas Steam	38	206

ICF