IMPACT OF HB1500 & SB2627 ON THE ERCOT MARKET

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TABLE OF CONTENTS

TABLE OF ABBREVIATIONS

A/S	Ancillary Services
CC	Combined Cycle
CONE	Cost of New Entry
CT	Combustion Turbine Generation
DR	Demand Response
DRRS	Dispatchable Reliability Reserves Service
EE	Energy Efficiency Programs
EFOR	Equivalent Forced Outage Rate
EFORD	Equivalent Forced Outage Rate Demand
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GADS	Generating Availability Data System
GW	Gigawatt
ICAP	Installed Capacity
IMM	Independent Market Monitor
kW	Kilowatt
LFG	Landfill Gas
LOL	Loss of Load
LOLE	Loss of Load Expectation
LOLH	Loss of Load hours
LOLP	Loss of Load Probability
MW	Megawatt
MWh	Megawatt-hour
PRM	Planning Reserve Margin
PUCT	Public Utility Commission of Texas
SERVM	Strategic Energy & Risk Valuation Model

EXECUTIVE SUMMARY

This report includes an assessment of the impacts of two major energy bills from the Texas 88th Regular Legislative Session: HB1500 and SB2627.

HB1500 includes multiple provisions, including "guardrails" for the implementation of the Performance Credit Mechanism (PCM), firming requirements for new generation sources, and the directive to implement a Dispatchable Reliability Reserve Service (DRRS).

SB2627 provides low-cost loans for dispatchable generation sources and bonuses for new sources that come online in the next few years.

Analyzing these bills, we found that:

- None of the scenarios modeled provide the necessary financial incentives to increase net thermal capacity in the short-term.
- The PCM program will cost more than $1B to achieve the desired level of reliability, even with the most efficient possible implementation.
  - The PCM, as implemented by HB1500, would only achieve a Loss of Load Expectation (LOLE) of about 0.9 – about nine times higher than the 0.1 LOLE (electricity outage rate of just one day in ten years) target.
  - We estimate that, to achieve the target 0.1 LOLE, the net cost of the PCM program would be between $1.5B – $2B, depending on its final implementation structure.
  - Compared to scenarios with a PCM cap, doubling or eliminating the PCM cap reduces short-term generation retirements by 50 percent or more.
- More firming capacity is needed in the winter than in the summer for every resource class except for solar.
  - We find that firming requirements do not achieve the level of reliability required even if combined with the current PCM structure.
- It is possible to achieve the desired level of reliability through the Dispatchable Reliability Reserve Service (DRRS) program with similar levels of resources needed as in the PCM.
  - DRRS revenue is expected to be much more volatile than PCM payments because these revenues are driven by scarcity conditions, which may not occur every year and might suffer the same high investment decision discounting of the current market's scarcity revenue.
- The loan program associated with SB2627 is currently structured as a one-time subsidy, and thus there is no guarantee with its existing design that its implementation will spur additional investment once its terms expire.
  - The low-cost loan program can reduce the cost of implementing the PCM, but it is not by itself able to achieve the reliability target level.

INTRODUCTION

At the conclusion of the Texas 88th Regular Legislative Session, Governor Abbott signed two major pieces of legislation that will impact the Texas electricity sector: Texas House Bill 1500 (HB1500) and Texas Senate Bill 2627 (SB2627).

HB1500 includes multiple provisions, including "guardrails" for the implementation of the Performance Credit Mechanism (PCM), firming requirements for new generation sources, and the directive to implement a Dispatchable Reliability Reserve Service (DRRS), among other things.

SB2627 provides low-cost loans for dispatchable generation sources and bonuses for new sources that come online in the next few years.

This analysis focuses on the impact of HB1500 and SB2627 on the ERCOT market.

Specific to HB1500, this analysis considers:

1) The impact of the $1B cost cap placed on the PCM.

2) The impact of the firming requirements and penalties for new generation.

3) The market impacts of the DRRS.

Specific to SB2627, this report:

1) assesses the impact of the generation completion bonus on the Cost of New Entry (CONE), Market Equilibrium Reserve Margin (MERM), and its resulting impact on the PCM or other reliability service;

2) analyzes the impact of state financing incentives on CONE, MERM, and their resulting impact on PCM or other reliability service.

In general, the purpose of this report is to quantify the impact of each policy on the resulting level of reliability and what it costs. The target reliability metric is the Loss of Load Expectation (LOLE) (outages/year), which measures how often the grid is expected to experience some firm load shed due to macro grid dynamics – e.g., times when demand exceeds supply – over a specific duration of time.

Historically, a grid with a LOLE of 0.1 is considered to be reliable. A LOLE value of 0.1 means that the grid is expected to experience outages only once every ten years due to insufficient supply to meet demand.

A LOLE value higher than 0.1 indicates that the grid will experience outages more often than once in ten years, and a LOLE of less than 0.1 indicates that the grid will experience outages less often than once in ten years. For example, this analysis indicates that the ERCOT grid currently has a

1.71 LOLE, meaning it's reasonable to expect a loss of load event lasting 1.71 days (about 41 hours) every year.

The second major consideration in this work is the expected annual system costs associated with the market changes driven by each of the policies. The total annual cost is calculated as the sum of the energy market costs, ancillary services costs, and any reliability payments made to generators.

Some of the policies considered include caps on the amount of money to be spent on certain reliability products. For those, we assess the impact of those caps on system reliability.

Other policies include language that sets targets for certain grid resources, but these targets were not always clear. Thus, we interpreted them to require enough to achieve the level of desired reliability (0.1 LOLE) and then assessed the impact of acquiring those resources on total system costs.

Where possible, we considered the impact of combining these policies. However, because final rulemaking was not complete when this analysis was conducted, it is sometimes unclear how the policies might impact each other. HB1500 contains three major provisions and SB2627 contains another. Each of these is being implemented and/or considered on the heels of the Summer 2023 implementation of the ERCOT Contingency Reserve Service (ECRS), which further complicates an analysis of each on its own merits based on historical market expectations.

METHODOLOGY

To model the impact of HB1500 and SB2627 on the ERCOT market, IdeaSmiths partnered with Astrapé Consulting to analyze these market changes using their SERVM modeling platform. The SERVM modeling platform has been widely used to study electricity markets and the impacts of policy changes. Detailed information about the model is included in the Appendix. It is important to note that the final and actual implementation of the legislation through the regulatory policy making process and the resulting development of ERCOT protocols may differ from the assumptions used. Note that in all of the scenarios modeled in our work, "system costs" refer to the sum of the total energy + AS revenue and any reliability payments associated with the program implementations.

HB1500 PCM cost cap scenarios

Before the finalization of the HB1500 language, many aspects of the implementation of the PCM were considered. In general, the major aspects considered included a PCM cost cap, generation resources eligible to receive the PCM credits, and how the program costs would be allocated.

The final bill language states that the PCM program is bound by a $1B net cost cap[1], that only dispatchable generation resources are eligible to receive PCM credits[2], and that costs of the PCM program are allocated to load[3] as has historically been done with other ancillary services.

To assess each of the HB1500 provisions considered in this analysis, it is instructive to model more iterations than the final version to better understand the impacts of each. To that end, we modeled 1) the impact of the price cap being both gross and net, 2) the ability of renewables to receive PCM credits or not, and 3) the cost allocation of the PCM program to both load and generation resources.

Table 1 summarizes the eight HB1500 PCM cost cap scenarios considered in this analysis.

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[1] Annual PCM credit costs net of reduced energy market costs cannot exceed expected energy market costs without the PCM program by more than $1B per year.

[2] Thus, wind, solar, and load resources are excluded from receiving PCM credits.

[3] As opposed to individual generators or classes of generators.

Table 1: Table of PCM cost scenarios considered in this analysis.

Scenario	PCM?	Cost cap?	RE PCM eligible?	PCM cost allocation to renewables?
S1	No	n/a	n/a	n/a
S2	Yes	No	Yes	No
S3	Yes	$1B (gross)	No	No
S4	Yes	$1B (gross)	Yes	No
S5	Yes	$1B (gross)	Yes	Yes
S6	Yes	$1B (gross)	No	Yes
S7	Yes	$1B (net)	No	No
S8	Yes	Yes (net)	No	No

Scenario 1 (S1) is our counterfactual Business as Usual (BAU) case against which the other scenarios are measured when considering a cost cap (gross and net) for the PCM.

Scenario 2 (S2) is an "efficient PCM" case where all aspects of the PCM program that reduce its total costs while still achieving the required reliability standard are considered. Specifically, S2 does not include a cost cap on the PCM[4], makes renewable energy resources eligible for PCM credits, and does not allocate the costs of the PCM program to generators.

Scenarios 3 – 6 (S3—S6) evaluate the impact of a gross $1B PCM cost cap on system costs and reliability, considering each combination of renewables' PCM eligibility and allocation of costs.

Scenario 7 (S7) evaluates the PCM as close to the language of HB1500 as possible such that the $1B cost cap is a net cost cap, renewables are not eligible for PCM credits, and PCM costs are allocated to load and not to renewables.

Scenario 8 (S8) solves for what the net cost cap would need to be if S7 fails to achieve the required level of reliability. Essentially, S8 solves for the minimum net cost that the current iteration of the PCM, as otherwise implemented by HB1500, would need to achieve the desired level of reliability.

HB1500 firming cost scenarios

Next, we modeled the impact of firming costs for each of the previously considered PCM cost cap scenarios. Given our understanding of the bill language, we assumed that any resources utilized for firming requirements would not be eligible to participate in the energy market or provide any other service besides firming. Thus, this service was treated as a pre-contracted emergency-only

[4] Arbitrary caps are rarely efficient mechanisms for controlling costs while also targeting a specific level of reliability.

set of generation resources, as the Texas Energy Insurance Program would have been implemented via Texas Senate Bill 6, had it not failed to pass during the session.[5]

Essentially, the total firming capacity required for each scenario was calculated based on the amount of each type of asset realized in each scenario. As per the bill language, firming requirements for each resource class were computed as the difference between the worst performance across any simulation and the median performance.

HB1500 DRRS cost

While details are scarce, we find that the implementation of DRRS will essentially mimic the behavior of a shift in the Operating Reserve Demand Curve (ORDC). As documented by Potomac Economics, the Independent Market Monitor (IMM) for ERCOT, the recent introduction of another ancillary service product, the ERCOT Contingency Reserve Service (ECRS), has caused “shortage pricing for energy and AS [Ancillary Services] when the market is not short.”[6] However, it is understood that some of these issues will be abated with the completion of real-time co-optimization of energy and ancillary services (RTC), a planned ERCOT system upgrade, expected in 2026. Nevertheless, we expect similar effects from introducing DRRS and modeled them as such for this report.

There have been a few suggestions about the “how" of implementing DRRS concerning modifying the non-spin requirements and shifting the ORDC curve. However, this analysis was not designed to identify the most robust manner in which a DRRS product should be implemented. Instead, we focused on the magnitude of the product that would be required to get the system to CONE and achieve a 0.1 LOLE.

Because of the shortage of program details, we considered only two DRRS scenarios as compared to the same BAU case as above. The first DRRS scenario procures the same amount of the new ancillary service every hour, and the second procures double the amount of the service during the solar hours.[7] The amount of hourly DRRS needed in each hour in each scenario was then solved to achieve the desired level of reliability or 0.1 LOLE.

SB2627 scenarios

Senate Bill 2627 (SB2627) provides a $100/kW completion bonus and low-cost loans for net new capacity of conventional power plants larger than 100 MW. Using EIA overnight build costs and fixed operational and maintenance costs (FOM) and a reduced return on equity rate due to a state-sponsored loan, we estimate that the cost of new entry (CONE) would temporarily drop from 135.76 $/kW-year to 115.70 $/kW-year. The general impact of a lower CONE is to incentivize new

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[5] https://legiscan.com/TX/text/SB6/id/2771623

[6] https://www.ercot.com/files/docs/2023/09/15/imm-as-methodology-for-wmwg-091523.pdf

[7] It has been suggested that DRRS would be sized to alleviate renewable forecast uncertainty, thus the reason for our second method.

generation to be built even if expected revenues are lower than what would have previously been required to incentivize new entry.

This analysis considered five scenarios to compare the impacts of SB2627 and their differences are shown in Table 2.

Table 2: This analysis of SB2627 considered five scenarios.

Scenario	PCM limit?	SB2627 implemented?
BAU (no 2627)	n/a	No
BAU (with 2627)	n/a	Yes
PCM $1B Gross Cap	Yes ($1B gross)	Yes
PCM $1B Net Cap	Yes ($1B net)	Yes
PCM @ 0.1 LOLE	No	Yes

Note that SB2627 also includes other energy provisions, such as $1.8B for microgrids at critical facilities and another $1B for transmission and distribution upgrades for Texas locations outside of ERCOT. However, for the purpose of this analysis, we only considered the parts of SB2627 associated with the low-cost loan program for facilities inside ERCOT.

RESULTS & DISCUSSIONS

In general, the Results and Discussion section focus on the impact of each policy change on 1) the reliability of the ERCOT system as measured by LOLE, and 2) the total system cost.

HB1500 results

This section focuses on the cost and reliability impacts of the policies contained in HB1500, including the PCM net cost cap, resource-class firming requirements, and implementation of the DRRS.

Impact of the PCM cost cap

Table 2 shows the implications of the PCM cost cap as laid out in the scenarios in Table 1.

Table 3: The implications of the $1B cost cap on the PCM for different scenarios is shown below.

Scenario	PCM?	Cost Cap?	RE PCM eligible?	PCM cost allocation to renewables?	LOLE (days/year)	Renewable Capacity (GW)	Thermal Retirements (GW)	Energy + AS Revenue (B$/yr)	Reliability Payments (B$/yr)	Total System Cost (B$/yr)
S1 (BAU)	No	n/a	n/a	n/a	1.71	85.28	13.48	19.91	0	19.91
S2	Yes	No	Yes	No	0.1	85.28	2.99	11	10.38	21.38
S3	Yes	$1B gross	No	No	1.38	76.76	11.85	20.4	1	21.4
S4	Yes	$1B gross	Yes	No	1.48	85.28	13.09	18.98	1	19.98
S5	Yes	$1B gross	Yes	Yes	1.35	59.7	9.15	23.64	1	24.64
S6	Yes	$1B gross	No	Yes	1.31	51.17	7.74	24.87	1	25.87
S7	Yes	$1B net	No	No	0.91	76.76	10.77	17.7	3.21	20.91
S8	Yes	No	No	No	0.1	76.76	1.63	12.36	9.51	21.87

An analysis of the **Business as Usual (BAU) case (S1, no PCM program)** indicates that the ERCOT system can expect a total system cost of about $19.9B in 2025. This system would see the deployment of about 85 GW of renewables and the retirement of about 13.5 GW of thermal resources. S1 results in a LOLE value of about 1.71, which is much higher than the 0.1 LOLE target. A LOLE of 1.71 indicates that on average a grid can expect to lose power for over 17 days over a ten-year span. However, this is the scenario all subsequent scenarios will be compared against when determining their total system cost impacts.

Scenario 2 (S2) details the results of the "efficient PCM" scenario where no cost cap is imposed, but renewables are eligible for PCM credits, and PCM costs are allocated to load. Because there is no cost cap on the PCM, it can achieve the desired level of reliability (LOLE of 0.1). Thermal retirements are found to be much lower - only about 3 GW compared to 13.5 GW in S1. Thus, **our analysis finds an uncapped PCM can help achieve the legislative intent of reducing retirements of thermal generation capacity while still meeting reliability goals.** From the BAU (S1), energy and (traditional) ancillary services revenues decrease by about \$8.9B, but the scenario requires about \$10.38B in total PCM payments to achieve the desired level of reliability, for a net cost increase of about \$1.5B over S1. Note that this scenario is not how the PCM is currently defined by statute (renewables are not eligible for PCM credits in the current rules). But it is our attempt to determine the most efficient pathway forward. As such, this analysis indicates that, even with the most efficient implementation of the PCM program, it will cost at least \$1.5B to achieve the desired level of reliability.

Scenarios 3 – 6 each represent a scenario where the gross PCM costs were limited to \$1B. Each scenario individually considered all the cases where renewables were eligible (or not) for PCM payments and/or if the PCM costs were allocated to generators rather than to load. **None of the \$1B gross cap scenarios achieve the reliability target (0.1 LOLE). Significantly, each gross cost cap scenario cost more overall.** The highest cost cases were those that allocated PCM costs to renewables (S5 & S6). The lowest gross cap case (S4) did not allocate PCM costs to renewables and allowed renewables to receive PCM credits. Thus, we conclude that excluding renewables from the PCM system or saddling them with the reliability costs do not achieve the legislative goals of affordably meeting the reliability target and minimizing thermal retirements.

Scenario 7 (S7) considers the implications of the PCM as written in HB1500. In this scenario, a net cost cap of \$1B is enforced; renewables are not eligible for PCM credits but are also not allocated their costs. **The modeling indicates that this scenario does not achieve the desired reliability level.** This scenario fares marginally better but still only achieves a LOLE of 0.91 – about 9 days over a ten-year span, or 9 times higher than the reliability target. In this scenario, we see about 2.7 GW fewer thermal retirements, with about \$2.2B lower overall energy market costs. These lower energy costs make room for about \$3.2B in PCM payments for a net increase of \$1B over BAU.

Scenario 8 (S8) was constructed to estimate how large the net cost cap would have to be to achieve the desired reliability level (0.1 LOLE) while also satisfying the other parts of the current PCM implementation. Solving for the total net PCM payments needed to achieve 0.1 LOLE requires about \$1.96B, or about \$960M more than the original \$1B net cost cap. This scenario sees far fewer thermal retirements, only about 1.6 GW as compared to 13.5 GW, about \$7.6B in lower energy market costs, but about \$9.5B in gross PCM payments. **Thus, this analysis indicates that any net cost cap below approximately \$2B under the current definition of HB1500 is unlikely to achieve the level of reliability desired.**

It is important to note that this $2B net cost increase is the weighted average value of the 2,000+ probabilistic modeling runs used to create these results. For reference, the total system cost values for S8 ranged from about $20B to $23.7B (10th and 90th percentiles, respectively), and S1 (BAU) ranged from $9.7B to $37.2B (10th and 90th percentile, respectively) indicating that the annual variability in net cost of achieving a LOLE of 0.1 via the PCM could range from an additional cost of $10.3B ($20B vs. $9.7B) to a savings of $13.5B ($23.7B vs. $37.2B).

It is also important to recognize that these expected value results differ from those calculated by Energy and Environmental Economics, Inc. (E3) in their report "Assessment of Market Reform Options to Enhance Reliability of the ERCOT System" to the PUCT.[8] Their analysis estimated a net cost increase of only about $460M for the PCM program.

This analysis differs in two major ways: 1) we assumed a much higher CONE value of 135.76 $/kW-yr. than 93.5 $/kW-yr assumed by E3., and 2) our analysis indicated that the hours of highest reliability risk were no longer in the summer but in the winter months.

A higher CONE directly increases the cost of the PCM program while the seasonal shift in reliability hours changes the nature of reliability events. Winter reliability concerns are marked by short-duration, extreme impacts whereas summer reliability concerns can persist for weeks or months at a time. This shift to short, infrequent reliability events in the winter results in a lower market equilibrium, or a bigger shortfall in capacity that must be made up by a reliability product. This shift is also associated with less scarcity pricing at the 0.1 LOLE RM which results in the need for more supplemental revenue for capacity, further increasing the cost of reliability.

Impact of firming requirements

The second major provision of HB1500 considered here is the firming requirement across each resource class. Firming requirements were computed at each resource class level, except for storage, as per HB1500 language. Firming requirements for each resource class were computed as the difference between the worst performance across any simulation to the median performance. For example, the combined cycle resource class showed a need for a 4% firming requirement in the summer (Figure 1) and a 6% firming requirement in the winter (Figure 2).

[8] https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2

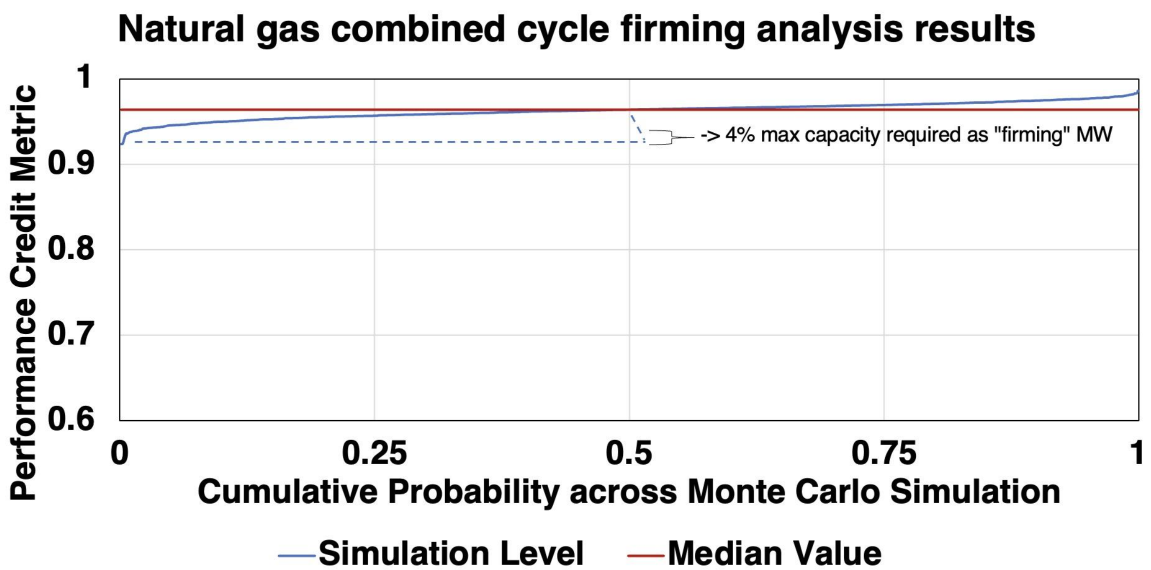

Figure 1: The results of a Monte Carlo simulation were used to determine the level of firming capacity needed for the natural gas combined cycle class for the summer season.

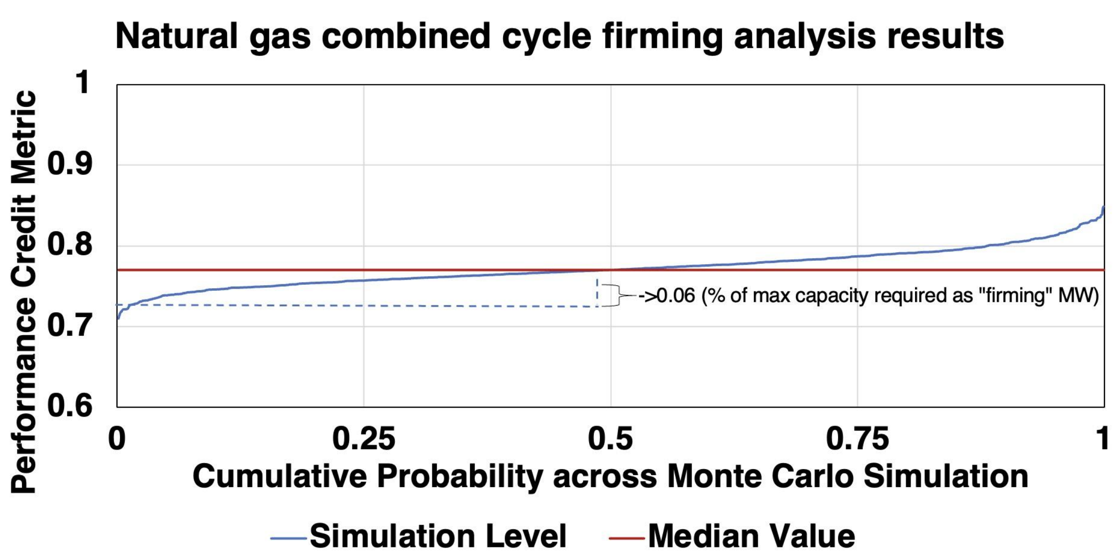

Figure 2: The results of a Monte Carlo simulation were used to determine the level of firming capacity needed for the natural gas combined cycle class for the winter season.

Table 4 shows an example of the firming requirements, by all resource class levels, for both the summer and winter seasons for the $1B net cost scenario (S7).

Table 4: The firming requirements for each resource class as well as a comparison of the summer and winter capacities needed for the $1B net cost scenario (S7) are shown below.

Resource Class	Summer (%)	Winter (%)	Summer (MW)	Winter (MW)
Natural Gas Combined Cycle	4%	6%	122	197
Natural Gas Turbine	7%	11%	121	199
Solar	0.7%	0.4%	58	34
Wind-Coastal	13%	23%	141	245
Wind-Other	9%	18%	505	1,014
Wind-Panhandle	19%	38%	173	352
Total			1,129	2,057

In general, this analysis found that there was more firming capacity needed in the winter than in the summer for every resource class, except for solar. However, this analysis found that firming requirements for solar were very small relative to other resource classes.

Taking these resource class requirements and applying them to each scenario's final capacity results (as shown in Table 3) yields the firming requirement results shown in Table 5.

Table 5: Table showing the impacts and costs of firming capacity on system reliability assuming $135/kW-year for firming costs.

Scenario	LOLE without firming (days/year)	LOLE with firming (days/year)	Summer Firming Capacity (GW)	Winter Firming Capacity (GW)	Cost to Acquire Firming Capacity (M$/yr)
S1	1.71	1.22	1.17	2.14	$ 289
S2	0.10	0.08	1.22	2.22	$ 299
S3	1.38	0.88	1.07	1.96	$ 265
S4	1.48	0.75	1.17	2.14	$ 290
S5	1.35	0.92	0.88	2.16	$ 291
S6	1.31	0.97	0.79	1.44	$ 194
S7	0.91	0.61	1.07	1.97	$ 265
S8	0.10	0.08	1.13	2.06	$ 278

Across all scenarios, the total amount of winter firming capacity required was greater than that of the summer capacity required and was thus used to calculate the cost to acquire the firming capacity. This point is important as most of the historical focus in ERCOT has been on summer reliability.

Including the firming capacity increased the level of reliability (lower LOLE) across all scenarios, but was not enough for all scenarios to achieve the target. Scenarios that already achieved a LOLE of 0.1 using just the PCM program alone (S2 & S8) resulted in a LOLE lower than 0.1, but also came with an additional cost of between $278M and almost $300M. The BAU case and all the $1B gross cap scenarios (S1 & S3-S6) saw improvements in reliability, but none achieved the target, each still being 7-9 times above it. Firming requirements in the $1B net cost case (S7) saw an improvement in the LOLE, but it was still not enough to achieve the desired level of reliability.

Impact of DRRS

This analysis assessed the impact of DRRS in two ways: 1) by assuming that the amount of resources procured was flat across all hours of the year (Figure 3), and 2) that the capacity required in solar hours was double that of the non-solar hours (Figure 4).

Flat DRRS Implementation												
Hour of Day/Month	1	2	3	4	5	6	7	8	9	10	11	12
1	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
2	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
3	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
4	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
5	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
6	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
7	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
8	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
9	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
10	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
11	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
12	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
13	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
14	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
15	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
16	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
17	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
18	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
19	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
20	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
21	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
22	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
23	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42
24	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42	5.42

Figure 3: The amount of DRRS capacity needed to achieve a LOLE of 0.1 if the same amount of capacity is procured for every hour of the year is shown above.

Solar-Shaped DRRS Implementation												
Hour of Day/Month	1	2	3	4	5	6	7	8	9	10	11	12
1	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
2	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
3	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
4	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
5	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
6	3.68	3.68	3.68	3.68	3.68	7.36	3.68	3.68	3.68	3.68	3.68	3.68
7	3.68	3.68	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	3.68	3.68
8	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
9	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
10	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
11	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
12	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
13	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
14	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
15	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
16	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
17	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
18	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36
19	3.68	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	7.36	3.68	3.68
20	3.68	3.68	3.68	7.36	7.36	7.36	7.36	7.36	3.68	3.68	3.68	3.68
21	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
22	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
23	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
24	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68

Figure 4: The amount of DRRS capacity needed to achieve a LOLE of 0.1 if the amount of capacity procured is twice as much during the hours of the day when solar is expected to be producing power is shown above.

Solving these levels of DRRS to achieve a LOLE of 0.1 resulted in about 5.46 GW for the flat procurement case and a procurement of 3.68 GW for the non-solar hours and 7.36 GW for the solar hours for the solar-shaped DRRS procurement case. The implications of these cases are shown in Table 6.

Table 6: The impacts of the DRRS cases relative to the BAU case show that DRRS increases costs but meets reliability goals.

Scenario	LOLE (days/year)	DRRS Volume (GW)	Thermal Retirements (GW)	Total System Cost (B$/yr)
BAU	1.71	0	13.48	19.91
Flat DRRS	0.10	5.42	2.89	21.61
Solar Shaped DRRS	0.10	3.68/7.36	2.65	21.92

The hourly and daily shape of the DRRS procured can affect the pricing impact of DRRS; although our analysis suggests that whether DRRS is flat or mimics the shape of the daily expected renewable profile, the total cost to incentivize adequate new capacity to supply 0.1 LOLE reliability is relatively similar.

Further, the size of DRRS required to achieve 0.1 LOLE results in program costs that are similar to the PCM scenario that was allowed to solve to a LOLE of 0.1 (S8). Total system costs at 0.1 LOLE via DRRS are between $21.6B and $21.9B as compared to $21.4B for an efficient PCM program where all resources are eligible for PCM revenues (S2).

Thus, at model equilibrium, it is expected that the DRRS program is somewhat interchangeable with the PCM program. As such, a smaller (perhaps roughly half-sized) DRRS program would be needed to bring other PCM scenarios, such as the S7 scenario that most closely follows the HB1500 language, to a reliability of 0.1 LOLE.[9]

However, it is important to note that DRRS revenue is expected to be much more volatile than PCM payments because these revenues are driven by scarcity conditions, which may not occur every year and might suffer the same high discounting of the current market's scarcity revenue by some generators. Thus, it is not clear that DRRS or other such ancillary services would move forward prices in a way that would send investment signals.

SB2627 results

This section outlines the results from the analysis of SB2627, which provides completion bonuses and low-cost loans to dispatchable generators, excluding energy storage.

We estimate that the implications of SB2627 will be to temporarily lower the Cost of New Entry (CONE) of new market participants from about 135.76 $/kW-year to 115.70 $/kW-year. The main idea is that a lower CONE would spur the deployment of new generation resources to come into the market. Further, we assumed that the low-cost loan program could be fully subscribed to if the market equilibrium would support such investments. Table 7 lays out the results of the impact of SB2627 for each scenario considered.

[9] Note that this analysis distinguishes explicitly between the DRRS and PCM scenarios. We identified the magnitudes in terms of PCM economics and the size of the DRRS product that would be required to get the system to CONE and 0.1 separately. We find that the system can achieve reliability targets and be at equilibrium using both separately as well as a combination of the two approaches. However, our work did not quantitatively try to assess combinations of PCM implementation, along with DRRS product sizing.

Table 7: The impacts of SB2627 with and without the PCM, all Net Present Values (NPV) values in 2025$USD indicate that, while SB2627 can temporarily lower the cost of the implementation of the PCM, it is not enough to get to the desired reliability level.

Scenarios	LOLE (days/year)	Renewable Capacity (GW)	Thermal Retirements (GW)	Energy + AS Revenue (B$/yr)	Reliability Payments (B$/yr)	Total System Cost (B$/yr)	NPV Total System Cost (2025 – 2035) (B$)
BAU (no 2627)	1.71	85.28	13.48	19.91	0	19.91	171
BAU (w/ 2627)	1.37	85.28	12.93	18.57	0	18.57	160
PCM $1B Gross Cap	1.11	76.76	11.67	19.12	1	20.12	173
PCM $1B Net Cap	0.8	76.76	10.59	17	2.57	19.57	168
PCM with 0.1 LOLE	0.1	76.76	1.98	12.36	8.04	20.4	175

The results of the scenarios find that SB2627 can reduce the cost of new entry and thus total system costs but is likely not enough to get the system to the desired 0.1 LOLE reliability level. Comparing the BAU case with and without SB2627 shows a marginal reliability increase, but the BAU (w/ SB2627) 1.37 LOLE is still almost 14 times below the target as the net level of expected thermal retirements is still high.

In general, it is expected that some new generation is likely to come online, but it is likely to be mostly offset by older plants retiring. None of the scenarios modeled indicated that net thermal capacity would increase by implementation of the program.

This result is partly because the market would still depend on scarcity pricing, sending a long-term investment signal to power plant developers, who would be helped by a subsidized CONE but are still likely to be heavily discounted as they are today. The program would also come with its own implementation costs and presumably would have to be continuously refunded by legislation if it proved to be the only tool used to incent new dispatchable generation.

Considering the impact of SB2627 in conjunction with the PCM does yield some interesting insights. The PCM program, depending on how it is implemented, could see some short-term benefits from the implementation of SB2627. In general, the combination of the two programs provides both a market entry subsidy (low-cost loans and completion bonuses) and a possible future revenue stream (PCM payments). The low-cost loan program is expected to reduce the cost of the PCM program by temporarily decreasing the costs for those projects that would also get the PCM credits. This combination results in slightly fewer thermal retirements and lower total system costs.

For the $1B PCM gross cost cap case, the SB2627 version sees about 180 MW fewer thermal retirements and a reduced total system cost of about $1.28B/yr but still only achieves a 1.11 LOLE (vs. a 1.38 LOLE without SB2627). For the $1B PCM net cost cap case, the SB2627 version also sees about 180 MW fewer thermal retirements and a reduced total system cost of about $1.34B/yr. This version achieves a marginally better 0.8 LOLE (vs. a 0.91 LOLE without SB2627), but it is still about eight times higher than the 0.1 LOLE target level.

For the case where we solved for the amount of PCM payments it would take to achieve a 0.1 LOLE, we find that the SB2627 version can do so for about $1.41B/yr less than the non-SB2627 version. A lower amount of PCM payments drives the difference in the total system costs between these scenarios needed ($8B/yr vs. $9.5B/yr) in the SB2627 version.

We also assessed the ten-year impacts of each of these scenarios and found that the net present values (NPV)[10] are not that different and all within about 10% of each other. The BAU case without SB2627 shows the NPV of total 2025-2035 market costs to be about $171B. The BAU case with SB2627 shows a lower ten-year cost of about $160B, driven by lower expected energy and ancillary market costs over that period. The ten-year costs of the $1B PCM net cap scenario costs about $168B, which is less than the $1B PCM gross cap scenario because of lower total market costs, even when considering higher PCM payments. The highest ten-year costs are for the only scenario that achieves the target 0.1 LOLE at about $175B.

However, it is important to note that the loan program associated with SB2627 is currently structured as a one-time subsidy. There is no guarantee that its implementation will see it fully allocated or spur additional investment once its terms expire because subsidies for mature technologies don’t generally increase learning rates and reduce costs like they can for nascent ones. Thus, while not directly modeled in this analysis, it is expected that the same market fundamentals that are driving the current sector dynamics would take over afterward and this program would essentially push the current trends of thermal retirements and growing wind and solar into the future.

10 Discounted back to today by 8%. https://www.ercot.com/files/docs/2017/05/22/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf

CONCLUSIONS

This analysis sought to assess the impact of HB1500 and SB2627 on the evolution and costs of the ERCOT market.

We find that the current cost cap of $1B/yr is an impediment to achieving a reliable grid through the PCM program because it does not provide enough funding to incentivize sufficient generation capacity.

We do find that it is possible to achieve the desired level of reliability through the PCM program, but it will cost, on average, about $1.5B to $2B/year.

Further, we found that firming capacity requirements do not achieve the level of desired reliability. Solving for the amount of DRRS needed to achieve the desired 0.1 LOLE results in costs comparable to that of the PCM, but these revenues are expected to be much more volatile and thus might be heavily discounted by generators, similar to how scarcity pricing is considered today.

We also find that the completion bonus and low-cost loan program of SB2627 reduces the costs of some of the components of HB1500 but are not enough to achieve the levels of reliability sought under either PCM cost cap scenario. While SB2627 does reduce the cost of the achieving a 0.1 LOLE via the (uncapped) PCM by about $1.41B/yr in the short-term, the program is designed to expire, and thus its impact will fade, and the same market fundamentals that ERCOT is experiencing today will return.

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ABOUT US

IdeaSmiths LLC

IdeaSmiths LLC[12] was founded in 2013 to provide clients with access to professional analysis and development of energy systems and technologies. Our team focuses on energy system modeling and assessment of emerging innovations, and has provided support to investors, legal firms, and Fortune 500 companies trying to better understand opportunities in the energy marketplace.

Astrapé Consulting

Astrapé Consulting LLC[13] was founded in 2005 by Kevin Carden. Astrapé redeveloped SERVM on behalf of The Southern Company from 2005-2007. Since then, Astrapé has managed and enhanced SERVM. Astrapé purchased SERVM from Southern Company in 2017 and licenses and uses the tool in jurisdictions across the United States, Europe, and Asia.

11 https://www.texasconsumer.org/

12 https://www.ideasmiths.net/

13 https://www.astrape.com/

APPENDIX

The SERVM model

The Strategic Energy & Risk Valuation Model (SERVM) is a comprehensive energy system planning tool developed by Astrapé Consulting that provides sophisticated economic and reliability modeling of bulk energy systems. SERVM captures the intricacies of ERCOT's wholesale market design and projected system conditions for 2024 and uses probabilistic simulations to evaluate the economic and reliability implications of various proposed market design solutions under different reserve margins, weather conditions, and other uncertainties.

In ERCOT, the Market Equilibrium Reserve Margin (MERM) concept is crucial because, unlike other bulk energy systems in North America, ERCOT does not have a resource adequacy reliability standard or reserve margin requirement. Instead, the reserve margin is ultimately determined by the suppliers' costs and willingness to invest based on market prices, which are determined by market fundamentals and the administratively determined Operating Reserve Demand Curve (ORDC) during tight market conditions.

SERVM leverages various advanced modeling techniques, including Monte Carlo simulations, stochastic modeling, and dynamic programming, to provide reliable and comprehensive assessments of the economic and reliability impacts of different market design proposals. By integrating detailed economic and engineering data with probabilistic modeling, SERVM offers a powerful tool for evaluating the potential outcomes of different market design scenarios regarding system economics and reliability.

Leading energy companies, utilities, and regulators in North America and overseas have widely adopted SERVM. Its flexibility, accuracy, and robustness make it an essential tool for assessing and managing bulk energy systems' financial risks and reliability.