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PROJECT NO. 54335

REVIEW OF MARKET REFORM	§	**PUBLIC UTILITY COMMISSION**
ASSESSMENT PRODUCED BY	§	**OF TEXAS**
ENERGY AND ENVIRONMENTAL	§	
ECONOMICS, INC. (E3)	§	

COMMENTS OF ROBERT L. BORLICK OF BORLICK ENERGY CONSULTANCY

I respectfully submit these comments in response to the Public Utility Commission of Texas (PUCT) request for a review of the Market Reform Assessment performed by Energy and Environmental Economics, Inc. (E3).

SUMMARY

After reviewing the quantitative results of the E3/Astrapé ("E3") analysis of alternative reliability enhancing options, I disagree with the recommendation to implement a Forward Reliability Market (FRM). The additional costs that this, (or any other) reliability enhancing option would impose on electricity consumers, does not justify the monetary value of the benefits it would provide. For this reason I recommend that the ERCOT Energy-Only Market be retained in its current form. However, if the PUCT wants to ensure an acceptable level of resource adequacy by adopting one of the reliability-enhancing options, it should do so by achieving the level of Expected Unserved Energy (EUE) that minimizes the total costs borne by electricity consumers, including those imposed on them through involuntary service interruptions. In addition, I recommend that the PUCT incentivize the development of robust retail demand response, which will increase ERCOT system reliability and further lower electricity customers' costs.

COST-BENEFIT ANALYSIS OF THE FIVE PROPOSED RELIABILITY OPTIONS

Table 1 compares the total system operating costs and the Loss of Load Expectations (LOLEs), of the six different market designs examined in the E3 Base Case analysis. These results reveal that four of the five reliability options would substantially improve system reliability, as measured by the Loss of Load Expectation (LOLE) metric, but at an annual cost increase ranging from about

TABLE 1 - SYSTEM COSTS BY CATEGORY FOR BASE CASE (BILLIONS $2026)[1]						
	Energy-Only	**LSERO & FRM**	**PCM**	**BRS**	**DEC**	**DEC/BRS Hybrid**
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Performance Credits			**$5.67**			
Backstop Service				**$0.36**		**$0.43**
Dispatchable Energy Credits					**$0.15**	**$0.15**
Total System Cost	**$22.33**	**$22.79**	**$22.79**	**$22.69**	**$22.82**	**$23.25**
Incremental Reform Cost		**+$0.46**	**+$0.46**	**+$0.36**	**+$0.49**	**+$0.92**
Loss of Load Expectation (Days/Yr.)	**1.25**	**0.10**	**0.10**	**0.10**	**2.03**	**0.10**

one-half billion to one billion dollars. The basic flaw in this comparison is that ***LOLE has no economic foundation***, consequently, it is useless for determining the ***monetary value*** of a change in system reliability.

In 2011 NRRI published a report that included the following statement:

> For decades, the utility industry has been using the 1-in-10 standard as the primary if not sole means for setting target reserve margins and capacity requirements in resource adequacy analyses. While the origination of the 1-in-10 metric is somewhat vague, there are multiple references to it in papers starting with articles by Calabrese from the 1940s. In the literature we surveyed, no justification was given for the reasonableness of the standard other than that it is approximately the level that customers were accustomed to. Because customers rarely complain about the level of reliability they receive under the 1-in-10 standard, few question the 1-in-10 metric as an appropriate standard.[1]

An article in Fortnightly Magazine further elaborated on the shortcomings of the LOLE metric).[2]

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for the depth of the outages (i.e., the number of MWs of load that were involuntarily interrupted). The PUCT should give no further consideration to LOLE or LOLH.

Fortunately, E3 calculated a third reliability metric that does have economic validity: the expected value of the amount of energy that is unserved (EUE). If one can assign an average monetary value to a MWh that is involuntarily interrupted, i.e., the Value of Lost Load (VOLL), then one can estimate the monetary benefit of a reduction in EUE.

VOLL has been extensively investigated since the early 1970s. In 2013 London Economics attempted to produce an estimate for VOLL in ERCOT but their results were inconclusive.[3] However, in 2015 the Lawrence Berkeley National Laboratories (LBNL) produced a meta-analysis of many past studies to produce consensus values of VOLL for various customer classes.[4] Table 2 summarizes the results of that study.

The LBNL meta-analysis reveals that residential customers are willing to pay less for service reliability than commercial or industrial customers. Thus, it is economically efficient to interrupt residential customers first when supply shortfalls exist because it minimizes societal cost.[5] For this reason I will assume that only residential customers are interrupted during almost all future ERCOT supply shortfalls, thus the VOLLs for this customer class are most relevant.

Table 2 reveals that residential customer VOLL prices for short (30 to 60 minute) interruptions range from $3.30 to $5.90 per kWh of unserved energy. Table 2 also reveals that the outage costs vary by season and time of day; however, the most likely times when supply shortages are likely to occur are during Summer afternoons and early evenings. The costs per interruption during these time periods are close to the weighted average costs for 30 to 60 minute outages.

The LBNL report expressed VOLL in 2013 dollars. To express them in mid-2026 dollars I

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5 From an equity perspective, the interrupted customers should also be compensated at their respective VOLL prices for the discomfort and inconvenience that service interruptions impose.

TABLE 2 - ESTIMATED INTERRUPTION COST PER EVENT, AVERAGE KW AND UNSERVED KWH BY DURATION AND CUSTOMER CLASS (IN 2013 US DOLLARS)						
Interruption Cost	**Interruption Duration**					
	Momentary	**30 Minutes**	**1 Hour**	**4 Hours**	**8 Hours**	**16 Hours**
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
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Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3
Residential, disaggregated by time of service interruption (Cost per Event)						
Summer Morning/Night	$6.8	$7.5	$8.4	$14.3	$24.0	$42.4
Summer Afternoon	$4.3	$4.9	$5.5	$9.8	$17.1	$31.1
Summer Evening	$3.5	$4.0	$4.6	$9.2	$17.5	$34.1
Non-Summer Morning/Night	$3.9	$4.5	$5.1	$9.8	$17.8	$33.5
Non-Summer Afternoon	$2.3	$2.7	$3.1	$6.2	$12.1	$23.7
Non-Summer Evening	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average:	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4

The interruption costs shown are for the average-sized customer in the LBNL meta-database.

The average annual kWh usages for the respondents in the meta-database are: 7,140,501 kWh for medium and large C&I customers, 19,214 kWh for small C&I customers and,13,351 kWh for residential customers.

Source: Lawrence Berkeley National Laboratory and Nextant Inc., "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," January, 2015.

multiplied by a factor of 1.32 to account for actual past and projected future inflation rates.[6] This yielded the range $4.36 to $7.79. To be conservative I used the higher estimate to estimate the cost of unserved energy in the six market designs.

Assuming that individual household curtailments can be limited to one hour or less, the forecasted monetary equivalent costs of the outages in 2026 associated with the existing Energy-only Market and the alternative reliability options are presented in Table 3.

TABLE 3 - COSTS AND BENEFITS OF EACH MARKET DESIGN OPTION IN THE BASE CASE

Market Design	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Annual System Operating Cost[1] ($ Billions/Yr.)	$22.33	$22.79	$22.79	$22.69	$22.82	$22.67
Expected Unserved Energy[2] (MWh/Yr.)	14,093	1632	1632	1632	15053	1632
Monetary Cost of Expected Outages[3] ($ Billions/Yr.)	$0.110	$0.013	$0.013	$0.013	$0.117	$0.013
Total System Cost Including Outages ($ Billions/Yr.)	$22.440	$22.803	$22.803	$22.703	$22.937	$22.683
Net Benefits of Reduced Outages[4] ($ Billions/Yr.)	0	($0.363)	($0.363)	($0.263)	($0.497)	($0.243)

TABLE NOTES

1. The Annual System Operating Costs were taken from Table 22 of the Consultant's report.
2. The Expected Unserved Energy (EUE) were taken from Table 18 of the Consultant's report.
3. The Expected Outage Costs were monetized by multiplying the Expected Unserved Energy by the Value of Lost Load (VOLL), which was assumed to be ($7790 per MWh).
4. The Net Benefits provided by each of the Reliability Options are relative to the current Energy-Only Market design. The table entries clearly reveal that all of the Reliability Options are substantially more expensive than retaining the current Energy-Only Market design.

The bottom line is that all of the alternative reliability enhancing options that meet the one-in-ten LOLE metric would impose a substantial additional cost burden on electricity consumers, ranging

[6] The past and projected future CPI inflation rates applied here were obtained from Statista, "Projected annual inflation rate in the United States from 2010 to 2027," Sept 30, 2022.

from about ***one-quarter to one-half billion dollars annually.*** If the PUCT decides to adopt one of these options to ensure an acceptable level of resource adequacy it should do so by achieving the level of EUE that minimizes total costs borne by electricity consumers, including the burden imposed through involuntary service interruptions.

The conclusion, that all of the reliability enhancing options that meet the one-in-ten LOLE metric would burden electricity consumers with unjustifiable costs, is based on a risk-neutral analysis, i.e., one that only examined the expected values of the costs. However, the value of increased system reliability may be justified by accounting for customers' risk aversion - their willingness to pay more to reduce the probability of being exposed to a major outage (like that which occurred during Storm Uri). [7] E3 did not address this important issue, perhaps because a rigorous methodology for accounting for customer risk aversion does not exis,.[8] Decision Analysis theory states that minimizing the expected value of cost is reasonable if the bearer of the cost can afford to absorb the worst case outcome.

ECONOMIC VALUE OF RETAIL DEMAND RESPONSE

One important attribute of an Energy-Only Market is that it provides a strong incentive for the development of price responsive demand (PRD). Capacity Market designs typically overbuild capacity to satisfy the one-in-ten LOLE metric, which excessively suppresses energy prices and discourages PRD development. Although ERCOT is an Energy-Only market, demand response is almost nonexistent among retail customers because few are exposed to ERCOT real time energy prices. The PUCT has done virtually nothing to facilitate retail demand response development despite having been encouraged to do so as far back as 2012.[9]

Residential customers represent the most attractive potential for PRD in Texas because they account for about half of the summer peak load. In 2012 ERCOT estimated that residential customers contributed about 53 percent to the 2011 Summer peak load. Small commercial

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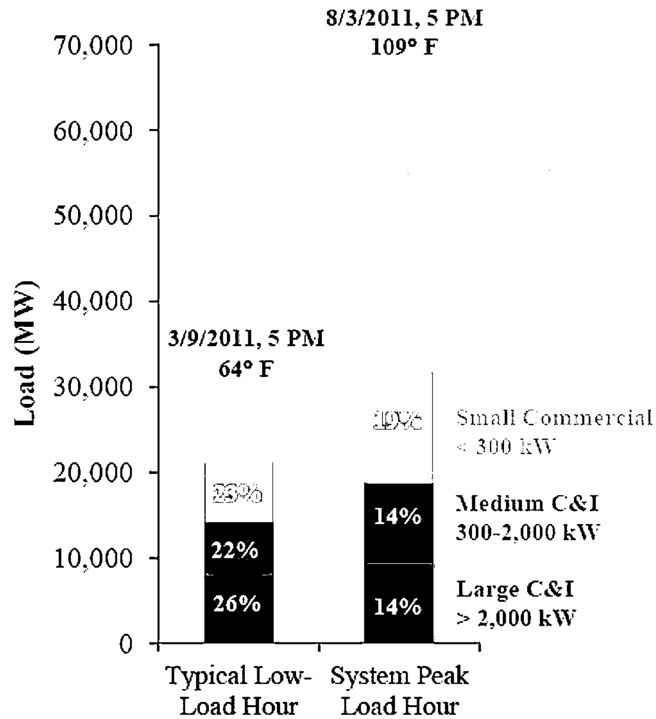
7 But note that none of the reliability enhancing options would have prevented the Storm Uri blackout because it was not caused by a lack of generating capacity. ERCOT had enough capacity to serve the high Storm Uri load if the plants had been able to run and if they had the natural gas needed to fuel them.

8 The National Regulatory Research Institute study cited earlier attempted to quantify the insurance value of increased system reliability but the analysis was based on insurance company practices, not electric customer risk aversion.

9 Sam Newell, *The Brattle Group*, "Resource Adequacy in ERCOT: 'Composite' Policy Options," Presentation to the PUCT, October, 2012.

customers contributed an additional 19 percent to that Summer peak. See Figure 1.

Figure 1 - Peak and Off-Peak Load by Customer Segment



Source: ERCOT. Reported temperatures are from Dallas.

Based on the outcomes achieved in other states, aggressive marketing combined with the free provision of enabling technology, (e.g., "smart thermostats, along with two-way communication) could induce about 20 percent of residential customer participation.[10] Typically, when the energy price that residential customers are exposed to reaches about fifteen times their normal tariff/contract price they reduce their combined demand by an average of 31 percent.[11] This price exposure can occur either by charging the customer the increased price or by paying the customer that price for his/her voluntary reductions in energy usage.

Texas law, HB-16, prohibits small customers being exposed to prices indexed to wholesale real-time prices, which would appear to rule out the first option described above, but perhaps not if the price charged is set in advance and not indexed to ERCOT's real time market prices. Thus, Retail

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[10] Ahmad Faruqui, *The Electricity Journal*, "Ten lessons in rate design: A meditation," December, 2022, p.5.

[11] *Id.*

Electricity Providers (REPs) could offer their customers Critical Peak pricing (CPP) or Variable Peak Pricing (VPP) products.[12] Also, HB-16 does not appear to prohibit offering customers products indexed to ERCOT day-ahead market prices so that's another product the REPs may be able to offer.

Combining the above information suggests that residential demand response could produce at least a three percent reduction in ERCOT's summer peak demand.[13] Three percent of the forecasted 2026 peak demand of 85,200 MW equals about 2,550 MW of peak load reduction.[14] This amount of residential demand response would reduce the EUE for the Energy-Only Market design from that which E3 reported but the exact amount cannot be quantified from the data in its report.[15] Furthermore, this is a lower-bound estimate of residential PRD potential because the participating customers could be exposed to prices at, or close to, the ERCOT energy price cap during the most serious ERCOT supply shortfalls. Such prices would exceed customers' normal contract prices by as much as a factor of fifty. During these extreme events their collective load reductions would almost certainly exceed three percent; by how much is unknown because no pilot programs deployed such severe price excursions.

The PUCT can incentivize retail customer demand response by requiring the TDSPs to provide enabling devices at no cost to their customers that sign up for REP demand response products. The TDSUs could then rate-base these investments. This scheme eliminates the conundrum that a REP faces if it invests in these devices when its customers can prematurely switch suppliers, leaving the former REP with unrecovered costs.

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[12] A CPP product applies a pre-determined higher energy price during a fixed time interval when a CPP event is called. The CPP price can be less than VOLL while still achieving a substantial level of load reduction. A VPP product is similar to CPP except that there are several predetermined prices that are selectively employed based on the amount of load reduction desired. Oklahoma Gas and Electric Company implemented the first successful VPP program in 2016, achieving a 20 percent participation rate.

[13] Residential customers contribute about half of ERCOT's summer peak demand, twenty percent of them participate in the DR programs, and reduce their combined demand by 30 percent (i.e., $0.5 \times 0.2 \times 0.3 = 0.03$). However, this assumes the CPP or PTR price is only 15 times the normal contract price, i.e., about \$1.50 per kWh. If the event price approaches ERCOT's energy market price cap (\$5.00 per kWh), one can expect customers to produce even larger demand reductions; consequently, the a three percent load reduction is a conservative estimate.

[14] ERCOT's forecast of the 2026 Peak load was taken from the E3 report.

[15] When PRD is deployed at prices below the ERCOT energy price cap (\$5.00 per kWh) it will restrain increases in the wholesale market energy price, which in turn will reduce the incentive for conventional generation to enter or remain in the market. For this reason the effective system reserve margin will increase by less than the load reduction effectuated by the PRD. This issue deserves to be explored in detail using SERVM.

The costs saved from retaining the existing Energy-Only Market design would easily exceed the cost of subsidizing enabling devices, making it a prudent investment. The saving in just one year could purchase and install about one million smart thermostats. From a public policy perspective subsidizing enabling devices is a big winner.

INTERRUPTED CUSTOMERS DESERVE COMPENSATION FOR THEIR LOSS OF SERVICE

Interrupted customers deserve to be compensated for the energy they would have consumed in order to offset their inconvenience. The obvious price to pay them is the ERCOT energy price cap (currently $5.00) for each kWh of foregone usage. Why? Bccause a REP saves that much on each kWh of his customer' interrupted load by not having to buy that energy at the wholesale market price.[16] For this same reason, it follows that the REPs should be the parties that pay for interrupted loads. Unfortunately, there doesn't appear to be any way to require the REPs to offer their customers products that provide for such compensation.

A second-best solution would be to require the TDSPs to pay the customers they interrupted (at ERCOT's request) and recoup those payments from ERCOT.[17] ERCOT would then recover those payments through uplifts to real time energy prices in the time intervals when the load curtailments occurred. This scheme would result in customers that were not interruptions in those time intervals to compensate those who were, which seems fair.[18] The PUCT appears to have the authority to mandate this second-best solution because it has jurisdiction over both the TDSUs and ERCOT.

[16] Note that it doesn't matter if a REP hedged the price of the curtailed energy because the counterparty will still paid the REP the wholesale market prices for the unconsumed hedged energy.

[17] However, when a customer is interrupted due to a distribution system failure the customer's TDSU should be required to absorb the payment it makes to that customer. This would provide a strong incentive for the TDSUs to maintain reliable distribution networks. Of course this risk will raise their cost of capital but the reduction in distribution system outages is likely to more than offset that cost.

[18] The gross inequity that occurred during Storm Uri, when some customers went without service for days on end while others enjoyed nice warm homes highlights the need for this change.

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The fundamental flaw in the E3 recommendation is that it is based solely on the "one-in-ten" LOLE reliability metric. However, this reliability metric lacks a rigorous economic foundation. In contrast, the Expected Unserved Energy (EUE) reliability metric does have a valid economic foundation. Applying this metric to the six market designs E3 examined reveals that the existing ERCOT Energy-Only Market imposes less cost on electricity customers than any of the reliability enhancing options, ranging from one quarter billion to one-half billion dollars in 2026.

I also recommend that the PUCT incentivize the development of robust retail demand response, which will increase ERCOT system reliability and further lower electricity customers' costs. The costs saved in one year by not implementing a reliability-enhancing option could cost-effectively fund demand response enabling technology for a million small customers.

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Non-Summer Evening	$1.5	$1.8	$2.2	$5.0	$10.8	$23.6
Weighted Average:	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4

The interruption costs shown are for the average-sized customer in the LBNL meta-database.

The average annual kWh usages for the respondents in the meta-database are: 7,140,501 kWh for medium and large C&I customers, 19,214 kWh for small C&I customers and,13,351 kWh for residential customers.

Source: Lawrence Berkeley National Laboratory and Nextant Inc., "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," January, 2015.

multiplied by a factor of 1.32 to account for actual past and projected future inflation rates.[6] This yielded the range \$4.36 to \$7.79. To be conservative I used the higher estimate to estimate the cost of unserved energy in the six market designs.

Assuming that individual household curtailments can be limited to one hour or less, the forecasted monetary equivalent costs of the outages in 2026 associated with the existing Energy-only Market and the alternative reliability options are presented in Table 3.

TABLE 3 - COSTS AND BENEFITS OF EACH MARKET DESIGN OPTION IN THE BASE CASE

Market Design	Energy-Only	LSERO & FRM	PCM	BRS	DEC	DEC/BRS Hybrid
Annual System Operating Cost[1] ($ Billions/Yr.)	$22.33	$22.79	$22.79	$22.69	$22.82	$22.67
Expected Unserved Energy[2] (MWh/Yr.)	14,093	1632	1632	1632	15053	1632
Monetary Cost of Expected Outages[3] ($ Billions/Yr.)	$0.110	$0.013	$0.013	$0.013	$0.117	$0.013
Total System Cost Including Outages ($ Billions/Yr.)	$22.440	$22.803	$22.803	$22.703	$22.937	$22.683
Net Benefits of Reduced Outages[4] ($ Billions/Yr.)	0	($0.363)	($0.363)	($0.263)	($0.497)	($0.243)

TABLE NOTES

1. The Annual System Operating Costs were taken from Table 22 of the Consultant's report.
2. The Expected Unserved Energy (EUE) were taken from Table 18 of the Consultant's report.
3. The Expected Outage Costs were monetized by multiplying the Expected Unserved Energy by the Value of Lost Load (VOLL), which was assumed to be ($7790 per MWh).
4. The Net Benefits provided by each of the Reliability Options are relative to the current Energy-Only Market design. The table entries clearly reveal that all of the Reliability Options are substantially more expensive than retaining the current Energy-Only Market design.

The bottom line is that all of the alternative reliability enhancing options that meet the one-in-ten LOLE metric would impose a substantial additional cost burden on electricity consumers, ranging

[6] The past and projected future CPI inflation rates applied here were obtained from Statista, "Projected annual inflation rate in the United States from 2010 to 2027," Sept 30, 2022.

from about ***one-quarter to one-half billion dollars annually.*** If the PUCT decides to adopt one of these options to ensure an acceptable level of resource adequacy it should do so by achieving the level of EUE that minimizes total costs borne by electricity consumers, including the burden imposed through involuntary service interruptions.

The conclusion, that all of the reliability enhancing options that meet the one-in-ten LOLE metric would burden electricity consumers with unjustifiable costs, is based on a risk-neutral analysis, i.e., one that only examined the expected values of the costs. However, the value of increased system reliability may be justified by accounting for customers' risk aversion - their willingness to pay more to reduce the probability of being exposed to a major outage (like that which occurred during Storm Uri). [7] E3 did not address this important issue, perhaps because a rigorous methodology for accounting for customer risk aversion does not exis,.[8] Decision Analysis theory states that minimizing the expected value of cost is reasonable if the bearer of the cost can afford to absorb the worst case outcome.

ECONOMIC VALUE OF RETAIL DEMAND RESPONSE

One important attribute of an Energy-Only Market is that it provides a strong incentive for the development of price responsive demand (PRD). Capacity Market designs typically overbuild capacity to satisfy the one-in-ten LOLE metric, which excessively suppresses energy prices and discourages PRD development. Although ERCOT is an Energy-Only market, demand response is almost nonexistent among retail customers because few are exposed to ERCOT real time energy prices. The PUCT has done virtually nothing to facilitate retail demand response development despite having been encouraged to do so as far back as 2012.[9]

Residential customers represent the most attractive potential for PRD in Texas because they account for about half of the summer peak load. In 2012 ERCOT estimated that residential customers contributed about 53 percent to the 2011 Summer peak load. Small commercial

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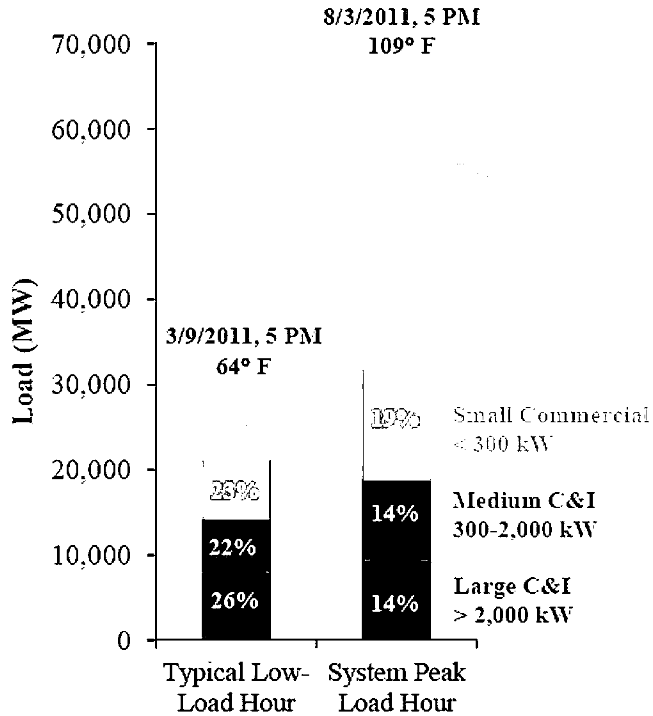
7 But note that none of the reliability enhancing options would have prevented the Storm Uri blackout because it was not caused by a lack of generating capacity. ERCOT had enough capacity to serve the high Storm Uri load if the plants had been able to run and if they had the natural gas needed to fuel them.

8 The National Regulatory Research Institute study cited earlier attempted to quantify the insurance value of increased system reliability but the analysis was based on insurance company practices, not electric customer risk aversion.

9 Sam Newell, *The Brattle Group*, "Resource Adequacy in ERCOT: 'Composite' Policy Options," Presentation to the PUCT, October, 2012.

customers contributed an additional 19 percent to that Summer peak. See Figure 1.

Figure 1 - Peak and Off-Peak Load by Customer Segment



Source: ERCOT. Reported temperatures are from Dallas.

Based on the outcomes achieved in other states, aggressive marketing combined with the free provision of enabling technology, (e.g., "smart thermostats, along with two-way communication) could induce about 20 percent of residential customer participation.[10] Typically, when the energy price that residential customers are exposed to reaches about fifteen times their normal tariff/contract price they reduce their combined demand by an average of 31 percent.[11] This price exposure can occur either by charging the customer the increased price or by paying the customer that price for his/her voluntary reductions in energy usage.

Texas law, HB-16, prohibits small customers being exposed to prices indexed to wholesale real-time prices, which would appear to rule out the first option described above, but perhaps not if the price charged is set in advance and not indexed to ERCOT's real time market prices. Thus, Retail

[10] Ahmad Faruqui, *The Electricity Journal*, "Ten lessons in rate design: A meditation," December, 2022, p.5.
[11] *Id.*

Electricity Providers (REPs) could offer their customers Critical Peak pricing (CPP) or Variable Peak Pricing (VPP) products.[12] Also, HB-16 does not appear to prohibit offering customers products indexed to ERCOT day-ahead market prices so that's another product the REPs may be able to offer.

Combining the above information suggests that residential demand response could produce at least a three percent reduction in ERCOT's summer peak demand.[13] Three percent of the forecasted 2026 peak demand of 85,200 MW equals about 2,550 MW of peak load reduction.[14] This amount of residential demand response would reduce the EUE for the Energy-Only Market design from that which E3 reported but the exact amount cannot be quantified from the data in its report.[15] Furthermore, this is a lower-bound estimate of residential PRD potential because the participating customers could be exposed to prices at, or close to, the ERCOT energy price cap during the most serious ERCOT supply shortfalls. Such prices would exceed customers' normal contract prices by as much as a factor of fifty. During these extreme events their collective load reductions would almost certainly exceed three percent; by how much is unknown because no pilot programs deployed such severe price excursions.

The PUCT can incentivize retail customer demand response by requiring the TDSPs to provide enabling devices at no cost to their customers that sign up for REP demand response products. The TDSUs could then rate-base these investments. This scheme eliminates the conundrum that a REP faces if it invests in these devices when its customers can prematurely switch suppliers, leaving the former REP with unrecovered costs.

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[12] A CPP product applies a pre-determined higher energy price during a fixed time interval when a CPP event is called. The CPP price can be less than VOLL while still achieving a substantial level of load reduction. A VPP product is similar to CPP except that there are several predetermined prices that are selectively employed based on the amount of load reduction desired. Oklahoma Gas and Electric Company implemented the first successful VPP program in 2016, achieving a 20 percent participation rate.

[13] Residential customers contribute about half of ERCOT's summer peak demand, twenty percent of them participate in the DR programs, and reduce their combined demand by 30 percent (i.e., 0.5 x 0.2 x 0.3 = 0.03). However, this assumes the CPP or PTR price is only 15 times the normal contract price, i.e., about $1.50 per kWh. If the event price approaches ERCOT's energy market price cap ($5.00 per kWh), one can expect customers to produce even larger demand reductions; consequently, the a three percent load reduction is a conservative estimate.

[14] ERCOT's forecast of the 2026 Peak load was taken from the E3 report.

[15] When PRD is deployed at prices below the ERCOT energy price cap ($5.00 per kWh) it will restrain increases in the wholesale market energy price, which in turn will reduce the incentive for conventional generation to enter or remain in the market. For this reason the effective system reserve margin will increase by less than the load reduction effectuated by the PRD. This issue deserves to be explored in detail using SERVM.

The costs saved from retaining the existing Energy-Only Market design would easily exceed the cost of subsidizing enabling devices, making it a prudent investment. The saving in just one year could purchase and install about one million smart thermostats. From a public policy perspective subsidizing enabling devices is a big winner.

INTERRUPTED CUSTOMERS DESERVE COMPENSATION FOR THEIR LOSS OF SERVICE

Interrupted customers deserve to be compensated for the energy they would have consumed in order to offset their inconvenience. The obvious price to pay them is the ERCOT energy price cap (currently $5.00) for each kWh of foregone usage. Why? Bccause a REP saves that much on each kWh of his customer' interrupted load by not having to buy that energy at the wholesale market price.[16] For this same reason, it follows that the REPs should be the parties that pay for interrupted loads. Unfortunately, there doesn't appear to be any way to require the REPs to offer their customers products that provide for such compensation.

A second-best solution would be to require the TDSPs to pay the customers they interrupted (at ERCOT's request) and recoup those payments from ERCOT.[17] ERCOT would then recover those payments through uplifts to real time energy prices in the time intervals when the load curtailments occurred. This scheme would result in customers that were not interruptions in those time intervals to compensate those who were, which seems fair.[18] The PUCT appears to have the authority to mandate this second-best solution because it has jurisdiction over both the TDSUs and ERCOT.

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[16] Note that it doesn't matter if a REP hedged the price of the curtailed energy because the counterparty will still paid the REP the wholesale market prices for the unconsumed hedged energy.

[17] However, when a customer is interrupted due to a distribution system failure the customer's TDSU should be required to absorb the payment it makes to that customer. This would provide a strong incentive for the TDSUs to maintain reliable distribution networks. Of course this risk will raise their cost of capital but the reduction in distribution system outages is likely to more than offset that cost.

[18] The gross inequity that occurred during Storm Uri, when some customers went without service for days on end while others enjoyed nice warm homes highlights the need for this change.

PROJECT NO. 54335

REVIEW OF MARKET REFORM	§	**PUBLIC UTILITY COMMISSION**
ASSESSMENT PRODUCED BY	§	**OF TEXAS**
ENERGY AND ENVIRONMENTAL	§	
ECONOMICS, INC. (E3)	§	

EXECUTIVE SUMMARY

COMMENTS OF
ROBERT BORLICK OF BORLICK ENERGY CONSULTANCY

After reviewing the quantitative results of the E3/Astrapé ("E3") analysis of alternative reliability enhancing options, I disagree with the recommendation to implement a Forward Reliability Market (FRM). The additional costs that this, (or any of the other) reliability enhancing option would impose on electricity consumers, would exceed the monetary value of the benefits provided by at least one-quarter billion dollars annually. For this reason I recommend that ERCOT Energy-Only Market be retained in its current form. However, if the PUCT wants to ensure an acceptable level of resource adequacy by adopting one of the reliability-enhancing options, it should do so by achieving the level of Expected Unserved Energy (EUE) that minimizes the total costs borne by electricity consumers, including those imposed on them through involuntary service interruptions.

The fundamental flaw in the E3 recommendation is that it is based solely on the "one-in-ten" LOLE reliability metric. However, this reliability metric lacks a rigorous economic foundation. In contrast, the Expected Unserved Energy (EUE) reliability metric does have a valid economic foundation. Applying this metric to the six market designs E3 examined reveals that the existing ERCOT Energy-Only Market imposes less cost on electricity customers than any of the reliability enhancing options, ranging from one quarter billion to one-half billion dollars in 2026.

I also recommend that the PUCT incentivize the development of robust retail demand response, which will increase ERCOT system reliability and further lower electricity customers' costs. The costs saved in one year by not implementing a reliability-enhancing option could cost-effectively fund demand response enabling technology for a million small customers.