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PROJECT NO. 40000

PROCEEDING RELATING TO §  
RESOURCE ADEQUACY IN THE §  
ERCOT POWER REGION §

PUBLIC UTILITY COMMISSION  
OF TEXAS

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**TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS IN RESPONSE TO  
DISCUSSION AT THE AUGUST 29, 2013 OPEN MEETING**

**I. INTRODUCTION**

Texas Industrial Energy Consumers (TIEC) submits these comments in response to the Commission's discussion at the August 29, 2013 Open Meeting. TIEC's member companies participated extensively in the creation of the ERCOT energy-only market. TIEC's members rely on the ERCOT market to provide reliable and competitively priced electricity, which is essential to the competitiveness of Texas industry. TIEC supports preserving the ERCOT energy-only market.

The Commission has recently made substantial changes to the ERCOT market design, including adopting an operating reserve demand curve (ORDC). This significant development will create additional revenues for resources providing energy or reserves, and will facilitate additional market response from both generators and loads. In response to this significant move, ERCOT forward prices have already increased. TIEC expects additional generation development activity as a result adopting the ORDC, along with the escalating System-Wide Offer Cap (SWOC), which will ultimately reach \$9,000 on June 1, 2015.

The Commission knows more now than it did even a few months ago, and should apply this new knowledge to the issues before it. As a result of Project No. 41060 and ongoing discussions, the Commission is now more cognizant of the significant flaws in the existing CDR Report assumptions. These flaws undermine the accuracy and reliability of any reserve margin shortfalls the CDR Report may predict. ERCOT is in the process of addressing some of those issues, but more needs to be done. Recent information also demonstrates that load is growing at a much lower rate than previously assumed. This impacts both the CDR Report and long-held assumptions about the level of generation development the market really needs, and indicates that the Commission has plenty of time to be deliberate in examining reserve margin and market design issues. Finally, recent developments in PJM and at FERC demonstrate that capacity markets in other areas of the country are not working as intended and are fraught with

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administrative complexity and ongoing legal battles. FERC is currently conducting a full scale review of its jurisdictional mandated forward capacity markets due to significant shortcomings in their design. The Commission should take great care in examining these issues before pursuing any dramatic market changes.

TIEC believes that the energy-only market is meeting and will continue to meet reliability objectives. For the most part, the claimed shortcomings of the energy market appear to be based on faulty assumptions and incomplete information. However, if the Commission wants additional regulatory control over the ERCOT reserve margin, TIEC has developed a new proposal, presented in Section D.1, below, that would provide this control with minimum interference to the existing market design. While TIEC continues to believe that these types of measures are not necessary, TIEC is committed to preserving the energy-only market, and to that end, believes it is important that the Commission have a full range of options before it. TIEC looks forward to discussing this proposal at the upcoming October 8<sup>th</sup> workshop.

## **II. RESPONSE TO COMMISSION QUESTIONS**

### **A. The Commission should assess the impact of recent market reforms before considering more radical government intervention.**

Since the summer of 2011, the Commission has taken significant steps to address resource adequacy issues, culminating in the recent decision to adopt Dr. William Hogan's operating reserve demand curve (ORDC) proposal with an aggressive 2,000 MW Minimum Contingency Level (MCL) and a \$9,000 value of lost load (VOLL). This important development replaced the prior offer floors for various ancillary services with a more comprehensive, principled approach. The ORDC will provide additional revenue to resources providing both energy and reserves, and will facilitate additional response from both generation and loads participating in the ERCOT market.

This significant market change complements the Commission's prior decision to triple the SWOC from its previous \$3,000/MWh level to \$9,000/MWh beginning on June 1, 2015. The Commission has also adopted "voluntary mitigation plans" (VMPs) for several generators with the largest market shares, including Luminant, Calpine and NRG, providing these generators with more bidding flexibility and further opportunities to increase their market revenues. As demonstrated by the significant generation development activity that has already

occurred, the market is responding to these changes. Given the magnitude of the decision to implement the ORDC, and the incremental SWOC increases scheduled for the next two summers, the market should be given additional time before the Commission embarks on more radical market changes.

Despite the claims of a few incumbent generators, there is no impending disaster or reliability emergency requiring radical action. Since the Commission began addressing resource adequacy concerns two years ago, more than 5,000 MW of new generation has been added to the resources included in ERCOT's Capacity and Demand Report (CDR). In addition to the well-publicized Panda plants, which add roughly 2200 MWs of efficient gas-fired generation, recent CDR Reports also include new thermal generation projects by NRG, Calpine, Golden Spread, LCRA, and others totaling 1,649 MWs. This does not even include the significant amount of renewable generation (wind and solar) that has been added to the CDR Report since May of 2012.

And this is just the tip of the iceberg. Public announcements and greenhouse gas (GHG) permit filings reveal that GDF Suez is constructing 134 MW of uprates, Invenegy is planning 330 MWs of peaking capacity, Southern Company is planning a 530 MW combined-cycle plant, MinnTex is pursuing 650 MWs of peaking capacity, Indeck is planning 650 MW of peaking capacity, STEC is constructing 225 MW of peaking capacity, Frontera is constructing 45 MW of uprates, and Tenaska and the Brownsville Public Utilities Board (BPUB) are jointly developing 800 MW of combined-cycle capacity in South Texas. These projects alone would add more than **3,500 MW** to ERCOT's resources. While TIEC acknowledges these projects may not all be constructed, conservative projections that account for all available resources (including mothballed generation) indicate that ERCOT would not fall below the current 13.75% target reserve margin for many years.

In addition to new generation, new demand response capability has also developed through new REP offerings and inventive new demand response products that complement the energy-only market design. Reducing ERCOT's peak demand is the single most efficient and effective way to reduce the amount of reserves needed to maintain reliability. New demand response capability has an even bigger effect on the reserve margin than new generation. To maintain the current reliability standard, each MW of demand must be met by 1 MW of

generation *plus* the target reserve margin. So, under today's 13.75% reserve margin, reducing peak demand by 1 MW would reduce the amount of generation capacity needed by 1.1375 MWs. Data from ERCOT also shows that residential loads (including residential air conditioning) comprise more than **50% of ERCOT's peak load**.<sup>1</sup> Recent advancements in market-based demand response for smaller customers are a significant step forward in ensuring resource adequacy. CPS recently developed a residential load aggregation to be offered into Non-Spinning Reserve Service (NSRS).<sup>2</sup> Other REPs are developing time-of-use products and other products that allow residential loads to be curtailed. "Passive" demand response capability (*i.e.*, customers curtailing usage on their own in response to high prices) is also increasing as the higher SWOCs take effect. This type of market response can be expected to continue as the ORDC is implemented and the SWOC continues to increase over the next two years, providing further incentive and opportunity for loads to respond to prices. While the precise quantity of new demand response is difficult to calculate because it is not subject to the same registration requirements as generation, these new developments demonstrate that loads are responding to the Commission's market design changes.

In short, the changes the Commission has made to the energy-only market to date *are working*. The Commission should not pursue any further, radical market overhauls until market participants have been given adequate time to respond to the recent changes and the impacts can be fully evaluated.

**B. The CDR Report systematically over projects reserve margin shortfalls that never materialize. The market does not believe these predictions, and the Commission should not take drastic action in response to these reports.**

The Commission should not base any sweeping market overhauls on shortfalls predicted in the CDR Report. As TIEC has noted previously, the CDR Report's current methodology is inherently structured to predict a reserve margin shortfall in "out" years, meaning more than two, three or four years in the future. The CDR Report forecasts expected load, which is growing, but does not forecast expected resources. Instead, the CDR Report includes only those generation resources with executed Standard Generation Interconnection Agreements (SGIAs), air permits,

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<sup>1</sup> See [www.ercot.com/content/meetings/other/keydocs/2013/0301-ERS/WeatherSensitiveERS\\_Overview\\_Workshop\\_030113.ppt](http://www.ercot.com/content/meetings/other/keydocs/2013/0301-ERS/WeatherSensitiveERS_Overview_Workshop_030113.ppt), Slide 3.

<sup>2</sup> See NPRR 532, approved at the most recent ERCOT Board meeting. This NPRR paves the way for a residential aggregation by CPS Energy to participate in the Non-Spinning Reserve Service and Loads in SCED.

and access to necessary water supplies. The standard development time for most generation projects is between two and three years;<sup>3</sup> therefore, few resources should be expected to have completed the steps necessary to be included in the CDR Report more than three years in advance of their in-service date. In contrast, there are no real “requirements” for proving that the CDR Report’s peak load projections will materialize and, instead, these forecasts are based almost exclusively on weather and economic projections—projections that have become increasingly unreliable.

This inherent bias has consistently caused the CDR Report to predict a reserve margin shortage two, three or four years in the future, which never materializes because new resources are brought to market during the intervening period.<sup>4</sup> The pattern of market participants and regulators overreacting to CDR Report projections, but then having sufficient capacity in the operating year, is by no means a new phenomenon. For example, in 2001, even with a 25% margin, the Commission “was concerned whether there were appropriate incentives to maintain a sufficient reserve margin in the future.”<sup>5</sup> The Commission initiated Docket No. 24255 to examine the issue of whether “capacity reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin.” The result of that docket was to “allow prices to rise in response to a scarcity of resources in the market,” using “competitive rather than regulatory methods” to facilitate sufficient capacity.<sup>6</sup> This decision has proven to be the right one. Despite the concerns expressed by some, the market has continuously responded and new resources have been added. Consistent with historical patterns, prior CDR Report releases showed a shortfall for the summer of 2014, but ERCOT is now predicting that it will exceed the current 13.75% reserve margin.<sup>7</sup>

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<sup>3</sup> Development time means the period after a project has completed initial planning, but prior to its in-service date. Some projects, such as coal and nuclear plants, can have longer development times, and some projects, such as wind generation facilities, have shorter development times.

<sup>4</sup> See, e.g., “Does Competitive Electricity Require Capacity Markets?” Kleit, Andrew N. and Michaels, Robert J., Ph.D (February 2013), available at: <http://www.texaspolicy.com/sites/default/files/documents/2013-01-RR02-ResourceAdequacyElectricityMarkets-CEF-RMichaelsAKleit.pdf>.

<sup>5</sup> See Docket No. 31972, Final Order at 5-6 (Aug. 24, 2006).

<sup>6</sup> *Id.* at 8.

<sup>7</sup> See ERCOT Press Release, May 1, 2013: [http://www.ercot.com/news/press\\_releases/show/26433](http://www.ercot.com/news/press_releases/show/26433).

The Commission should also be aware that many of the market participants who continue to make alarmist statements in response to CDR Report releases, and who continue to argue that a mandated forward capacity market is needed to maintain reliability, are telling a different story elsewhere. In comments supporting a move to retail choice in Arizona, a trade group representing Direct Energy, NRG, NextEra, Constellation and others admitted that the Texas energy market has “attracted over \$25 billion [in] generation investment for the construction of 39,000 MW of new capacity.”<sup>8</sup> The group also admitted “the outlook for dire consequences in Texas appears to be wholly overstated.”<sup>9</sup> Given these types of statements, the Commission should be skeptical of self-serving hyperbole from incumbent suppliers supporting capacity markets that are designed to advantage incumbent generation here in Texas.

To break this historical cycle of predicting shortfalls that never materialize and fomenting unjustified alarm in the market, the Commission should revise the CDR Report to better reflect reality and to better match investors’ expectations. At the August 29, 2013 Open Meeting, the Commission requested that parties file comments on the load forecast assumptions used in the CDR Report. TIEC was one of the only parties to file substantive comments on this issue in Project No. 41060. TIEC incorporates those comments by reference here,<sup>10</sup> but will provide a brief summary of the issues that cause the CDR Report to systematically over-forecast load, focusing on several specific issues related to load forecasting.

***1. ERCOT’s load growth forecast is still overstated.***

ERCOT previously determined that the load forecast it had been using was consistently too aggressive, and transitioned to using the “Moody’s Low Forecast” in the most recent CDR

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<sup>8</sup> Reply Comments of Retail Competition Advocates and the Retail Energy Supply Association (RESA) Addressing Retail Electric Competition Issues at 28, (Aug. 16, 2013), Arizona Corporation Commission Docket No. E-00000W-13-01350, available here: <http://images.edocket.azcc.gov/docketpdf/0000147417.pdf>. RESA’s members include: AEP Energy, Inc.; Champion Energy Services, LLC; ConEdison Solutions; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; GDF SUEZ Energy Resources NA, Inc.; Hess Corporation; Homefield Energy; IDT Energy, Inc.; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; NRG, Inc.; PPL EnergyPlus, LLC; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P.

<sup>9</sup> *Id.* at 28.

<sup>10</sup> Project No. 41060, TIEC Response to Commission Questions (Feb. 15, 2013) available at: [http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/41060\\_19\\_750202.PDF](http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/41060_19_750202.PDF).

Report. ERCOT noted that Moody's "low" forecast aligns more closely with historical load growth data in ERCOT during recent years.<sup>11</sup>

Despite this recent move in the right direction, ERCOT's load forecast still appears to be far too aggressive. ERCOT forecasted a peak load of 68,383 in the May 1, 2013 Seasonal Assessment of Resource Adequacy (SARA), which was 1.8% higher than the actual peak load of 67,180 MW from August 3, 2013.<sup>12</sup> It has been widely documented in the press that growth in electricity demand is no longer tracking economic growth as it has in the past, and load growth assumptions need to be modified significantly to reflect this new trend. A recent Reuters article attributed this phenomenon to new demand response products, specifically noting new products from TXU and CPS Energy, and gains in lighting and appliance efficiency.<sup>13</sup> IHS CERA provided information for the article noting that where demand used to grow at approximately twice the rate of Gross Domestic Product (GDP), it is now growing about 0.5% for every percentage point of growth in GDP. A recent Wall Street Journal article, "Electricity Use on Wane in the U.S.," similarly noted that "[f]or decades, electricity use was viewed as a barometer of economic growth, but the link has become less clear cut in recent years, partly because of a big push to make major appliances and other products, such as compact fluorescent lightbulbs and high-efficiency motors, that use less electricity."<sup>14</sup> This observation was based on recent information from the Energy Institute of America (EIA) projecting that growth in electric demand will grow an average of only 0.6-0.7% through 2040, as opposed to historical periods where growth was nearly 10%.<sup>15</sup> The following EIA chart demonstrates this trend:

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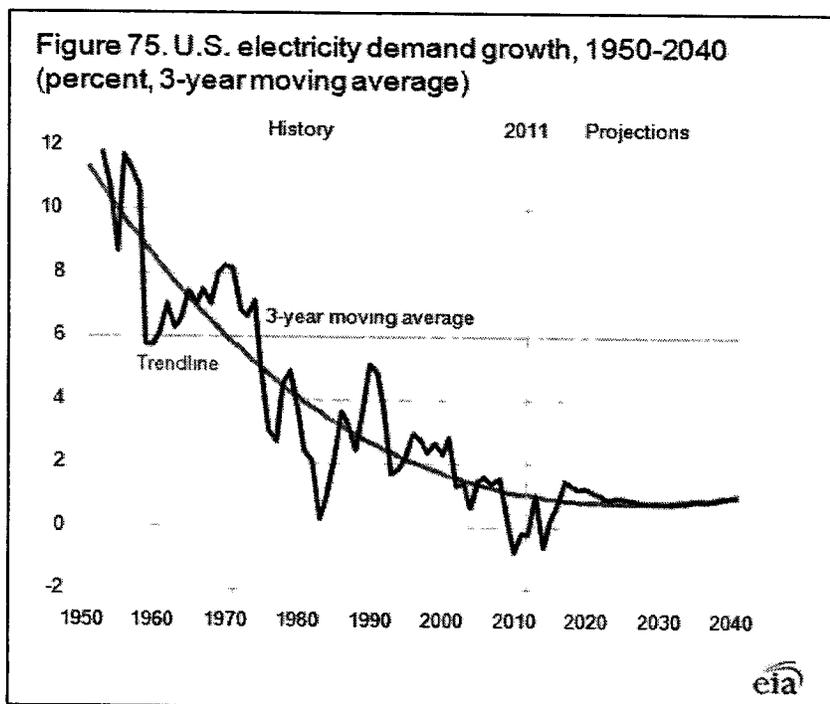
<sup>11</sup> 2013 ERCOT Planning: Long-Term Hourly Peak Demand and Energy Forecast at 10-12, available at: [http://www.ercot.com/gridinfo/load/2013 Long-Term Hourly Peak Demand and Energy Forecast.pdf](http://www.ercot.com/gridinfo/load/2013%20Long-Term%20Hourly%20Peak%20Demand%20and%20Energy%20Forecast.pdf).

<sup>12</sup> [http://www.ercot.com/news/press\\_releases/show/26528](http://www.ercot.com/news/press_releases/show/26528).

<sup>13</sup> "Texas Agency Puzzled by summer power use that didn't materialize," Reuters, (Sep. 13, 2013), available at: <http://www.reuters.com/article/2013/09/13/utilities-texas-demand-idUSL2N0H821W20130913>

<sup>14</sup> "Electricity Use on Wane in the U.S.," Wall Street Journal (Jan. 2, 2013), available at: <http://online.wsj.com/article/SB10001424127887323689604578217831371436110.html>.

<sup>15</sup> EIA study available here: [http://www.eia.gov/forecasts/aeo/MT\\_electric.cfm](http://www.eia.gov/forecasts/aeo/MT_electric.cfm).



While ERCOT has already taken steps to revise its load forecast, this information indicates that further refinements are needed. TIEC understands that ERCOT is already looking into this issue and anticipates revising the load forecast prior to the December 2013 CDR Report release; however, the recent versions of the CDR Report are likely materially over-forecasting future peak demand, even using the Moody’s Low Forecast. The Commission should recognize this significant shortcoming in the CDR Report’s projections and avoid making any dramatic market design changes based on predicted shortfalls.

**2. *The CDR Report’s total summer peak demand is unrealistically high.***

In addition to the load forecast issues related to economic growth projections, the CDR Report’s total summer peak demand forecast is also biased on the high side due to a combination of inaccurate or unrealistic assumptions.

First, the load forecast used in the CDR Report assumes that peak demand across all weather zones will occur coincidentally. Rather than relying on historical *system-wide* peak demand, the CDR Report’s load forecast assigns the historical high temperatures from *each weather zone* in ERCOT between June and September to the same hypothetical hour and weekday in August. In reality, the peaks may have been weeks or even months apart, and there is no empirical reason or technical support for assuming coincidence. This “pancaking”

approach ignores load diversity, exaggerates the likely system peak for future periods, and should be revised to use system-wide historical peak demand.

Second, the CDR Report does not accurately capture passive demand response<sup>16</sup> that has recently developed in the market or that occurs primarily during “super-peak” conditions. The Brattle Report identified a 1,700 MW load over-forecast error during peak periods, noting that “the extent of price-response programs is difficult to quantify exactly because pricing arrangements are a private contractual matter between REPs and their customers. Price-based load reductions were likely a major contributor to the 1,700 MW ERCOT load forecasting error in 2011 when prices reached \$3,000/MWh.”<sup>17</sup> Curtailment during an anticipated 4CP event was also cited as a possible reason for this significant over-forecast.<sup>18</sup> In addition, because the peak demand is based on historical conditions, new price-responsive demand will not be fully captured until it has sufficiently permeated the historical look-back period, which is currently 15 years. The CDR Report calculations should be revised to more accurately account for passive demand response. TIEC understands that ERCOT is focused on this issue and hopes that future load forecasts will be revised to better account for demand response.

### 3. *Wind capacity is undercounted.*

TIEC outlined several issues with the generation assumptions in the CDR Report in its prior comments in Project No. 41060. Two of the more significant issues were: (a) including only 50% of DC tie capacity in the CDR Report is arbitrary and this capacity amount should be increased, and (b) the current approach of including only a portion of the mothballed generation resources is unrealistic, ignores that ERCOT can procure these resources, and undercounts the available mothballed capacity.

In addition to these issues, the CDR Report is undercounting available wind capacity relative to the current 13.75% target reserve margin. The loss of load event study that recommended the current 13.75% target reserve in 2010 identified an effective load carrying

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<sup>16</sup> “Passive” demand response refers to voluntary load reductions as opposed to load reductions associated with an ERCOT-procured ancillary service or utility energy efficiency programs, which must also be captured in the CDR Report.

<sup>17</sup> Brattle Report at 89; *see also* Brattle Report at 55-56.

<sup>18</sup> *Id.* at 89-90.

capability (ELCC) for wind generation of 12.2%.<sup>19</sup> However, the CDR Report has continued to count only 8.7% of the installed wind capacity. Increasing the amount of wind being counted to match the number assumed in developing the current 13.75% target reserve margin would add another 445 MWs of capacity to the CDR Report for 2014.<sup>20</sup> The 2012 Loss of Load Study recommended even higher ELCCs for wind, with 32.9% for coastal wind and 14.2% for West Texas wind.<sup>21</sup> The ELCC for the CDR Report should match the target reserve margin to facilitate an accurate comparison. This current mismatch further skews the CDR Report in favor of a shortfall.

**C. Mandating a reserve margin is unnecessary, inefficient and misleading.**

For the reasons discussed above, the Commission should focus on refining the CDR Report methodology to better match reality and market expectations, and should give recent market changes time to work before making further changes. These are much more critical endeavors than mandating a reserve margin, which is unnecessary and will not guarantee reliability.

The vast majority of load shed events are not caused by a shortage of installed capacity. In fact, ERCOT has *never* had a reliability event caused by a lack of installed capacity, despite having operated without a mandatory reserve margin since electric restructuring. Over the past 13 years, every load shed incident has been the result of operational issues, like dramatic changes in wind output, extreme weather, or miscalculations in the load forecast.<sup>22</sup> Mandating a particular reserve margin will not protect against these types of operational events, as recently illustrated in PJM. Despite having a mandated reserve margin, a multi-billion dollar mandated forward capacity market, and an actual reserve level above 20%, “PJM was forced to direct local utilities . . . to immediately and temporarily cut electricity to some customers to avoid the

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<sup>19</sup> Item 7, Nov. 2010 ERCOT Board Meeting: <http://www.ercot.com/calendar/2010/11/20101116-BOD>.

<sup>20</sup> The May 2013 CDR shows 1,107 MW of wind for 2014. This is 8.7% of a total installed capacity of 12,724 MW. 12.2% of this total capacity would be 1,552 MW, for an increase of  $1,552 - 1,107 = 445$  MW.

<sup>21</sup> See Slide 3 of the following presentation to the ERCOT Board from the September meeting: [http://www.ercot.com/content/meetings/board/keydocs/2013/0917/7.2 Planning Reserve Margin Update.pdf](http://www.ercot.com/content/meetings/board/keydocs/2013/0917/7.2%20Planning%20Reserve%20Margin%20Update.pdf).

<sup>22</sup> See Commissioner Anderson, “Resource Adequacy in ERCOT” at Slide 5, available at: [http://www.puc.texas.gov/agency/about/commissioners/anderson/pp/ANALYSIS ERCOT CAPACITY RESERVE MARGIN 013013.pdf](http://www.puc.texas.gov/agency/about/commissioners/anderson/pp/ANALYSIS%20ERCOT%20CAPACITY%20RESERVE%20MARGIN%20013013.pdf).

possibility of an uncontrolled blackout”<sup>23</sup> on September 10, 2013. This example demonstrates that mandating a reserve margin will not guarantee reliability or prevent load shed.

The concept of a single, mandated reserve margin also ignores changes in year-to-year conditions and grid needs, resulting in inefficient resource procurement, excessive costs, and unintended market consequences. For example, the reserve margin needed to meet the extreme weather of 2011 (approximately 13.8%) was not needed in 2012 or 2013. Similarly, as the characteristics of loads and resources on the system change, the value of lost load, the ability of loads to respond shortage conditions, and forced outage rates (supply contingencies) will also change. This will directly influence the expected reserve levels needed to cover contingencies. To pick a single reserve margin number based on historical data and mandate that it be met every year is arbitrary in many senses, constitutes an unnecessary and ineffective form of government intervention, and will not guarantee that ERCOT will not experience rolling outages. To match the reserve margin in a given year with the grid needs in that particular year is unnecessarily complex, will require constant reexamination, and will be the source of endless market disputes. Rather than mandating a particular reserve level, the Commission should focus on ensuring that the energy market is designed properly to incentivize economic reserves by matching the costs of reliability with market impacts.

Regardless of whether the reserve margin is a target or a mandate, the current “1-in-10” reliability metric is outdated, arbitrary, ignores economic principles, and should be re-examined. This standard was carried over from the bundled utility days, and completely fails to consider the duration or magnitude of the firm load shed events being modeled to identify the reserve margin. In today’s competitive market, an appropriate reliability standard should consider the overall expected unserved energy that will result from a given reserve margin, which would capture both the duration and magnitude of expected events. TIEC supports moving from an arbitrary “one event” metric, to a standard that better captures the actual economic consequences of a loss of load event versus the cost of additional reserves.

To that end, TIEC strongly supports the Commission’s recent decision to identify the “economic” reserve margin for ERCOT’s energy-only market with analysis from the Brattle

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<sup>23</sup> See PJM News Release: “PJM Sets Record Sept. Peak Power Use Weather and Local Grid Conditions Require Load Reductions,” available at: [www.pjm.com/~media/about-pjm/newsroom/2013-releases/20130911-pjm-sets-record-september-peak-power-use.ashx](http://www.pjm.com/~media/about-pjm/newsroom/2013-releases/20130911-pjm-sets-record-september-peak-power-use.ashx).

Group. This type of analysis should help the Commission identify where improvements in reliability from additional reserves (*i.e.*, reductions in unserved energy) are not worth the additional cost to the market. Specifically, an economic reserve margin should identify the point where the cost of additional reserves exceeds the cost of the loss of load event those reserves would forestall. As discussed above, the economic reserve margin will likely change year over year depending on market conditions, so even under this analysis TIEC would oppose a single, mandated reserve margin. Instead, the concept of an economic reserve margin should be used to develop a target for the market, which will act as a barometer of whether the market is working as intended, or whether additional market design changes are needed.

#### **D. Options for Procuring Additional Reserves**

1. *If a mandatory reserve margin is adopted, the Commission should retain the current market design to the maximum extent possible and supplement it only as necessary with a new, longer-term ancillary service.*

As discussed above, mandating a single reserve margin is inefficient, ineffective, and unlikely to produce the desired results. If the Commission nonetheless adopts a mandated reserve margin, the Commission should preserve the existing energy market to the maximum extent possible, and should only apply out-of-market government intervention to procure the reserves that the market is not providing on its own. This can be achieved through a longer-term ancillary service that is only purchased when a reserve margin shortfall is predicted in the near-term. Like all ancillary services, the purpose of the new ancillary service would be to secure sufficient reserves to protect against contingencies and to better meet reliability objectives. As with all other ancillary services, ERCOT would determine the amount of capacity that needs to be purchased and would provide payments only to those resources providing the service, rather than procuring the entire market as a forward capacity market does.

TIEC previously proposed a load response “backstop” proposal that would be triggered when there is a predicted shortfall in the next summer’s expected reserves.<sup>24</sup> The procurement was limited to new demand responses resources, and would have included only the amount of capacity needed to bridge the difference between the expected and desired reserve margin. This

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<sup>24</sup> See TIEC Comments for Commission Workshop (Aug. 30, 2012). TIEC also believes that the prior proposal from Occidental Power Marketing L.P. is a viable and efficient option. See Comments of Occidental Power Marketing L.P. (Aug. 16, 2012).

proposal was directly responsive to the Brattle Report's observation that the ERCOT market should continue to develop additional demand response to increase the efficiency and effectiveness of the current energy-only design—particularly from small commercial and residential customers who contribute significantly to peak demand.<sup>25</sup>

While TIEC continues to believe that its demand response backstop is reasonable and viable, TIEC has developed a new proposal as a potential compromise. This new proposal would procure an ancillary service known as “Supplemental Reserve Service,” or SRS. The ancillary service would not be limited to demand response resources, but would allow for construction of new generation resources if necessary. The details of TIEC's proposal are outlined in “Exhibit A” to these comments. At a high level, SRS would be structured to include the following features:

- The shortfall in reserves needed to meet a reserve margin mandate would be procured on a least-cost basis.
- SRS energy would be deployed solely in place of rolling outages to avoid displacing any market generation.
- SRS energy would be offered at the SWOC to eliminate any market price suppression.
- SRS resources would be subject to operational, testing, credit, and reliability requirements to ensure that the resources meet the reserve need for which they were procured.
- SRS capacity payments would have to be refunded if the resource chooses to enter the market to avoid any subsidies among market competitors.

SRS preserves the features of the energy market that are working. It is a more targeted procurement, closer in time than most capacity markets, and guarantees a payment stream for 10 years rather than requiring auction participation year after year. As a result, SRS is more efficient, less invasive, and more effective than a forward capacity market. And most importantly, SRS provides the same or better assurance that a certain level of reserves will be available *at a much lower cost* than a forward capacity market. Using the cost of a peaking plant in the Brattle report (\$105/kW) and compressing the recovery over ten years, which is how SRS is structured, the net present value (NPV) cost of SRS would be \$2.2 billion over twenty years.

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<sup>25</sup> See Brattle Report at 5, Table 1.

In comparison, using the latest auction results in PJM, a mandated forward capacity market would create between \$25 billion and \$46 billion in unhedgeable costs over the same period.<sup>26</sup> Because a mandated forward capacity market pays *all* existing generators the same payment that the SRS resources would receive, procuring the same level of reserves would cost between ten and twenty times more under a forward capacity market. There will undoubtedly be different energy market pricing outcomes under the two constructs, but even if there are lower energy market costs under a forward capacity market (an outcome that assumes market equilibrium and is by no means assured), those theoretical energy cost savings will not offset the unhedgeable, out-of-market costs of a mandated forward capacity market. Therefore, if the Commission seeks to mandate a higher level of reserves than the energy market provides in any given year, SRS is a far more effective, narrowly tailored, and less costly approach than a mandated forward capacity market.

2. ***The Commission should not abandon the current successful energy-only market and start from scratch with a mandated forward capacity market. Capacity markets have proven costly, ineffective, and inefficient. The current FERC investigation should give the Commission even greater pause.***

TIEC has filed extensive comments outlining the problems with mandated forward capacity markets over the course of this project. The fundamental problem with capacity markets is that they create artificial demand by government mandate for a make-believe product—“capacity,” for which there is no demand independent of the energy produced—and then attempt to simulate the natural incentives of a competitive market through extensive administrative rules, mandates, and penalties. The proven inability to successfully replicate natural market incentives through government mandates and administrative penalties results in inefficiency, excessive costs, extensive legal battles, and constant market redesign. Despite the heavy-handed government intervention and associated costs, capacity markets can still fail to produce the reliability benefits regulators are seeking. TIEC will not repeat all of its prior comments here, but would direct the Commission to TIEC’s August 30, 2012 comments, which

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<sup>26</sup> This range is the variability of costs depending on whether you use the RTO-wide PJM auction results or the results for constrained areas.

address the shortcomings of forward capacity markets.<sup>27</sup> TIEC's October 23, 2012 comments also address the administrative complexity and excessive costs of capacity markets.<sup>28</sup>

The Commission need not take TIEC's word on the extensive costs, complexity, and ineffectiveness of forward capacity markets. These concerns are being borne out through real-world examples in other areas of the country. FERC recently opened a project to review virtually all design aspects of the current capacity markets, and is holding a technical conference on September 25, 2013, to examine fundamental issues like "how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs."<sup>29</sup> The comments filed by stakeholders in preparation for this workshop are illuminating and illustrate the significant and fundamental issues facing the capacity market construct. TIEC urges the Commission to review the comments filed in this FERC project. For instance, as the APPA noted in its comments to FERC:

The main challenge facing RTO-administered centralized capacity mechanisms today is that they have not been able to attain a mature, or even stable, state. To the contrary, as the large number of pending dockets listed in the August 23 Supplemental Notice (at 2-3) illustrate, *these mechanisms have proven to be a veritable fire hose of market rule revisions, contested proceedings, contested settlements and a number of court proceedings.* APPA believes that this is because the basic capacity procurement construct is flawed, and has been since inception. *The basic construct is not a "market" in any meaningful sense of the word.*<sup>30</sup>

APPA follows up its critique of current capacity markets with the following observation:

What APPA lacked the experience to appreciate in 2006, however, is that centrally-administered capacity constructs such as PJM's RPM would not only fail to work well for electric consumers, *they eventually would not work all that well even for incumbent generators.*<sup>31</sup>

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<sup>27</sup> TIEC Comments for Commission Workshop at 2-5 (Aug. 30, 2012), Interchange Item 288, available at: [http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000\\_288\\_735616.PDF](http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_288_735616.PDF).

<sup>28</sup> TIEC Comments in Response to Oct. 19, 2012 Brattle Presentation at 5-7 (Oct. 23, 2012), Interchange Item 328, available at: [http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000\\_328\\_739680.PDF](http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_328_739680.PDF).

<sup>29</sup> FERC Docket No. AD13-7, Notice of Technical Conference at 1 (Jun. 17, 2013).

<sup>30</sup> FERC Docket No. AD13-7-000, Written Statement on behalf of American Public Power Association (APPA) at 2 (Sep. 9, 2013), available here: [elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13346227](http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13346227).

<sup>31</sup> *Id.* at 3.

Finally, APPA comments on the overwhelming design complexity and ever-expanding rules to “plug the holes” that keep arising from the capacity market construct. According to the APPA:

At present, RTO-administered capacity constructs have a myriad of market rules that make them difficult to understand even for those in the industry, much less the retail electric consumers that have to pay the bills, or the lawmakers that represent them. *The successive attempts to patch each newly emergent failure that results from a construct that is not, in fact a market, has resulted in a set of tariffs and rules worthy of a Rube Goldberg cartoon.*

The APPA is not alone in these criticisms. State regulators in the PJM area have also been outspoken about the serious flaws in the capacity market construct. As the Maryland Public Service Commission noted in its comments to FERC:

In PJM, we have witnessed billions of dollars per year transferred from PJM consumers to capacity suppliers under the mistaken belief that this money is needed to keep the system operating reliably over the long term. Despite these wealth transfers, *we have seen little evidence to support the argument that this money is indeed producing the level of investment that is needed, when it is needed, and where it is needed, and doing so in a way that will provide reliable electric service at a reasonable cost.* Indeed, in response to this lack of new investment where needed and out of concern for the future reliability of electricity supplies in their respective regions, some parties in organized markets with a clearly defined jurisdictional responsibility to electricity users, including the States of Maryland, New Jersey and Virginia, have taken concrete steps to procure new capacity precisely because the centralized RTO/ISO markets on which we are told to depend have not demonstrated to our satisfaction that we can entrust the future energy security of our citizens on those markets.<sup>32</sup>

Even companies that support capacity markets are admitting that the current formulations are deeply flawed and are failing to deliver. For example, on a recent investor call, Calpine’s President and COO Thad Hill noted that many of the resources that “cleared,” and that are therefore obligated to show up, in PJM’s recent capacity auctions would not get built and that the auction revenue was insufficient to support generation development. As Mr. Hill stated: “. . . while the results of the auction were disappointing, we’d encourage people not to simply extrapolate those results forward. We say this for several reasons, including the fact that not all new plants cleared will likely get built . . .”<sup>33</sup> Despite being selected and paid through the most

<sup>32</sup> FERC Docket No. AD13-7-000, Maryland Public Service Commission Comments at 2 (Sept. 9, 2013).

<sup>33</sup> “Calpine Corporation (CPN) Management Discusses Q2 2013 Results - Earnings Call Transcript,” available at: <http://seekingalpha.com/article/1572982-calpine-corporation-cpn-management-discusses-q2-2013-results-earnings-call-transcript?page=4>. See also Energy Choice Matters; “SHOCK: Calpine Exec Says Not All

recent capacity auction, Mr. Hill believes that some of these resources will not show up as promised. Ironically, commentators have been noting that the penalties for “not showing up” are insufficient to guarantee that the resources selected in the auction will actually be available. According to a report from the UBS utilities market analysts:

Perhaps of greatest focus among PJM stakeholders of late is the lack of a meaningful penalty for those unable to deliver on their RPM commitments, capped at the *higher* of \$20/MW-day or 20% of the BRA result. Given the asymmetric return profile with IA’s of late materially below base auctions, PJM is likely to significantly revise up penalties for non-performance; while exact details of reforms have yet to be formalized, we see revised penalties as being at least 50%+.<sup>34</sup>

Yet another problem is unreliable performance by the resources that are procured, illustrating that just because consumers have been obligated to pay for a resource does not mean that the resource has the incentive and capability to provide the type of reliability customers and regulators bargained for. This is a problem endemic to decoupling generator revenues from *actual performance* when the resources are needed. For example, the New England Independent System Operator (ISO-NE) stated in its comments to FERC, “[i]t is difficult to declare the capacity market a success if a significant number of the resources that have been selected and compensated as capacity resources fail to perform as needed.”<sup>35</sup> ISO-NE goes on, “[p]ut simply, the performance of many resources has been poor and there have not been any consequences in the capacity market for such poor performance.”<sup>36</sup>

The potential costs associated with inaccurate load assumptions in forward capacity markets should give the Commission further pause. Over-forecasting load has had devastating consequences for PJM customers, but changing these assumptions is complicated and controversial. As UBS has pointed out succinctly about PJM’s capacity market: “Despite the over-estimation of demand in recent auctions, PJM is not currently contemplating meaningful

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New Capacity Clearing PJM Capacity Market Likely to Get Built,” (Jul. 26, 2013) available at: <http://www.energychoicematters.com/stories/20130726b.html>.

<sup>34</sup> Investor Report from UBS Utilities: Demystifying PJM’s Incremental Capacity (Sep. 3, 2013) (copy can be provided upon request).

<sup>35</sup> FERC Docket No. AD13-7-000, ISO NE Comments at 5 (Sep. 19, 2013).

<sup>36</sup> *Id.* at 6.

reforms to its demand forecasting capabilities.”<sup>37</sup> The costs and consequences of inaccurate load forecasting in a capacity market construct can be acute. As the Public Power Association of New Jersey pointed out in its comments to FERC:

PJM moved ahead through the darkest days of the Great Recession with no apparent regard for rising unemployment, foreclosures, and business closings. It was clear that the economy would limit growth and that load would not achieve forecast levels. But the PJM load forecast was not adjusted at the time and auctions resulted in over-procurement. As a result, customers who survived the Great Recession are paying for their own high-priced capacity and for the capacity that is not being consumed by customers that did not survive.”<sup>38</sup>

In total, what these comments demonstrate is that, contrary to the suggestions of those supporting a capacity market here in Texas, *there is no successful forward capacity market model*. Instead, attempting to impose a forward capacity market in ERCOT will be costly, administratively cumbersome, will take many years and, in the end, is unlikely to achieve the results the Commission is seeking. There is no reason to go down this path when the energy-only market is working well and continuing to provide adequate reserves. If additional measures are needed to provide further market incentives to invest in Texas, or if the Commission believes that some type of out-of-market mechanism is needed to achieve a certain level of capacity, this can be accomplished without scrapping the existing market design and taking on the impossible task of developing a capacity market that is actually worth the trouble and cost.

Finally, the Commission should also be highly skeptical of the results-oriented analysis provided by NRG from Charles River Associates (CRA). As the Commission has previously experienced (for example, with the June 2012 SEIA-commissioned Brattle report declaring solar as the solution to ERCOT’s resource adequacy problems),<sup>39</sup> stakeholder-paid consultant reports can be designed to produce almost any outcome with the “right” assumptions, caveats and footnotes. A cursory review of the CRA report indicates that it set up a “straw-man” by assuming that an energy-only market will only produce an 8% reserve margin—despite thirteen years of actual ERCOT data to the contrary—assumed without scrutiny or analysis that a forward

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<sup>37</sup> Investor Report from UBS Utilities: Demystifying PJM’s Incremental Capacity (Sep. 3, 2013) (copy can be provided upon request).

<sup>38</sup> FERC Docket No. AD13-7-000, Public Power Association of New Jersey Comments at 3 (Sep. 11, 2013).

<sup>39</sup> Project No. 37897, “The Potential Impact of Solar PV on Electricity Markets in Texas,” The Brattle Group (commissioned by Solar Energy Industries Association) (Jun. 21, 2012).

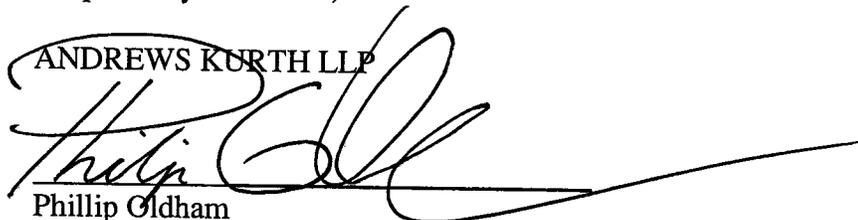
capacity market would produce a 13.75% reserve margin, and then calculated the cost of the difference in loss of load probability between the two. While this self-serving exercise should be ignored, it is worth noting that *NRG's own study assumed that a forward capacity market would cost \$4.6 billion annually.*

### III. CONCLUSION

TIEC appreciates this opportunity to provide comments on these critical issues and looks forward to discussing them with the Commission and other market participants at the workshop scheduled for October 8, 2013.

Respectfully submitted,

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ATTORNEYS FOR TEXAS INDUSTRIAL  
ENERGY CONSUMERS

**Supplemental Reserve Service (SRS) Proposal**

1. Before March 1 of each year, ERCOT will forecast peak demand for the four summer months occurring three summers in the future and the reserve margin needed to reliably meet that demand, taking into account realistic load growth assumptions and weather forecasts. For example, the forecast completed by March 1, 2014 would evaluate the June-September 2016 period.
2. ERCOT will then compare the total resource need identified under Section 1 to the expected resources for the same period to determine if a Reserve Deficit is expected.
3. If a Reserve Deficit is projected under Section 2, ERCOT will open an auction to procure new resources to provide Supplemental Reserve Service sufficient to meet the Reserve Deficit.
4. Resources wishing to provide Supplemental Reserve Service will submit bids based on a ten-year, levelized annual cost to ERCOT (Supplemental Reserve Service Payments).
5. ERCOT will select the resource or resources to provide Supplemental Reserve Service that will reliably meet the Reserve Deficit identified under Section 2 at the lowest overall cost, including any guarantees or credit necessary to ensure the resource is available.
6. Resources will be selected by June 1 of the procurement year to be on line by June 1 two years in the future.
7. Resources selected to provide the Supplemental Reserve Service are subject to appropriate testing and must meet credit, reliability, operational and availability requirements, consistent with the character of the service being provided.
8. Resources selected to provide Supplemental Reserve Service are committed for 10 years (Initial Term) and cannot otherwise participate in the energy or ancillary service markets, except as provided in Section 11.
9. Supplemental Reserve Service will only be deployed in lieu of instituting involuntary load shed and energy prices during any such deployments shall be set at the System Wide Offer Cap (SWOC).
10. Any revenues received by Supplemental Reserve Service Resources above verifiable, variable costs (fuel, operations and maintenance costs, etc.) will be credited back to the market on the same basis that the Supplemental Reserve Service Payments are billed.

11. Resources providing Supplemental Reserve Service may choose to leave the service to participate in the market at any time by repaying the Supplemental Reserve Service Payments received to date.
12. At the end of the Initial Term a resource providing Supplemental Reserve Service will no longer receive Supplemental Reserve Service Payments. After the Initial Term, if the resource is still needed and it has not opted to participate in the market under Section 11, it shall be paid its “to go” costs to operate plus 10% (as Reliability Must Run resources are paid today) until the unit is no longer needed or has exhausted its useful life.