PROJECT NO. 40480
COMMISSION PROCEEDING REGARDING
POLICY OPTIONS ON RESOURCE ADEQUACY

THE BRATTLE GROUP'S RESPONSES TO ENTITIES' TECHNICAL QUESTIONS TO BE ADDRESSED AT THE JULY 27, 2012 COMMISSION WORKSHOP

Texas Industrial Energy Consumers' (TIEC) Technical Questions for the Brattle Group

TIEC Question No. 1

Referring to p. 5, Table 1: Would Brattle describe the current ERCOT market design as most similar to Option #2, Energy –only with adders to support a target reserve margin? If not, please explain.

Brattle Group Response:

Yes, except that ERCOT also conducts capacity procurements of RMR and ERS resources. These backstop mechanisms are similar to Option #3, except that ERCOT does not limit their implementation to apply only at times when reserves fall below a "minimum acceptable" level (that would be set substantially below the reliability target) as we would recommend under Option #3.

ERCOT procures ERS resources for future contract periods on a regular basis. ERCOT's RMR procurements for capacity are more consistent with the Option #3 approach we proposed in that they are procured only when a projected reliability concern exists. However, there is not a formal "minimum acceptable" reliability level used to trigger these RMR procurements at a reserve level substantially below the target.

TIEC Question No. 2

Referring to p. 6: The report states that "imposing a resource adequacy requirement on LSEs is the most market-based, efficient option."

A. Please explain the basis for this statement.
B. Please cite to a market that currently has this design.
Does Brattle believe that the former PJM ICAP design that imposed a mandate on LSEs yielded an efficient outcome? Please explain.

Brattle Group Response:

A. Our report addresses that question directly in Sections VI.B.4-5. Note that the entirety of the quoted statement says that *if* policy-makers wish to achieve a specific target reserve margin and reliability level (as opposed to allowing the market to determine reliability outcomes), *then* imposing a resource adequacy requirement is the most market-based, efficient option. Imposing a resource adequacy standard is the most straightforward way to achieve that objective, by imposing a requirement that the market must fulfill. If the design is structured appropriately, then competitive pressures will assure that the reserve margin requirement is met at lowest cost.

B. MISO and California have designs of this sort implemented through short-term resource adequacy requirements on LSEs (although neither market is similar to ERCOT because in both cases most new generation is still developed through regulated cost recovery).[1] LSEs in these markets must procure sufficient capacity to meet their peak load plus a reserve margin using self-supply or bilaterally-procured capacity. Failure to meet the requirement results in penalties.

   The capacity markets of PJM, NYISO, and ISO-NE also impose resource adequacy requirements on LSEs. A major implementation difference between these markets and the bilateral capacity markets in MISO and California is that LSE deficiencies are not penalized; instead, these incremental unmet LSE requirements are procured by the RTO on behalf of the LSE through market-wide capacity auctions.

C. We have not analyzed PJM's former ICAP design in detail, although PJM and its market participants found that the design was deficient for a number of reasons. Quoting from a PJM filing before FERC, "that construct has the following serious shortcomings:

   - It does not look far enough into the future to secure capacity in time to meet reliability needs;
   - It lacks an important locational element;
   - It is not providing sufficient financial incentives for supply additions; and
   - Without revision, it will not ensure the future reliability of the region." [2]

TIEC Question No. 3

Referring to p. 6: The report appears to recommend raising the offer cap to $9000 regardless of the policy path selected by the Commission. Elsewhere in the report (e.g., pg. 71), however, Brattle notes that it should be set to the VOLL. In the same recommendation Brattle says that this cap should only be reached when load is actually shed, which would be different from an offer cap. Please clarify this recommendation, as ERCOT currently reaches the SWOC frequently when load is not shed. Is Brattle's real recommendation to conduct a study to determine what VOLL is and to reach VOLL only when load is shed?

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[1] Note that a major revision to MISO's current design has recently been approved by FERC. See: https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Orders/2012-06-11%20139%20FERC%2061,199%20Docket%20No.%20ER11-4081-000.PDF

[2] See pp. 4-9 of PJM's August 31, 2005 filing before the Federal Energy Regulatory Commission in Docket Nos. ER05-1410-000 and EL05-148-000.

Brattle Group Response:

Our recommendation is stated in the report – that scarcity prices should rise to a level consistent with the average VOLL when load is being shed and not before. Adopting our recommendation would reduce the frequency of hours at the price cap compared to current market rules. However, we also recommended introducing a more graduated scarcity pricing mechanism(s) that would result in a continuum of high prices that increase with the severity of the scarcity event, as discussed in Sections V.A.2.c-d.

We also recommended creating a functional distinction between the "offer cap" imposed on suppliers, the administrative "price cap" that would be imposed during load shed events,[3] and various other administrative scarcity pricing thresholds as explained in Section V.A.2.b. We believe that it is important to distinguish among these different parameters because they have very different purposes and therefore may appropriately have different values. For example, even if the price cap is increased to $9,000/MWh, it may be appropriate to limit the offer cap on suppliers to a lower value consistent with the market monitor and PUCT's mitigation framework.

We expect that VOLL is "in the ballpark" of $9,000 based on previous VOLL studies, but this number is subject to substantial uncertainty. It may be beneficial to conduct a VOLL study in ERCOT that considers the VOLL of various customer classes, as well as the types of customers that are actually shed under the TDSPs' load shedding protocols. We expect that such a study would identify a range of VOLL estimates that could be appropriate, with the range likely including $9,000/MWh.

TIEC Question No. 4

Referring to p. 6: Alberta has an energy-only market and a price cap of $1000. A recent Brattle report, "Evaluation of Market Fundamentals and Challenges to Long-term System Adequacy in Alberta's Electricity Market," concluded that "Alberta's energy-only market is generally well-functioning and sustainable, although its efficiency and effectiveness can be improved with some design changes." Please explain why the Alberta energy-only market is sustainable but the ERCOT market is not in Brattle's view.

Brattle Group Response:

We did not conclude that the ERCOT market is unsustainable, only that the current market structure under current market fundamentals will not support enough investment to achieve ERCOT's reliability target.

By comparison, Alberta does not specify a reliability target. However, in conducting our analysis of the Alberta market under current conditions, we projected that market-based revenues

3 Note that ERCOT does not currently have a price cap and so prices may exceed the system-wide offer cap in some special circumstances. We recommended imposing a true price cap, consistent with VOLL, that will not be exceeded.

will likely be sufficient to attract new generation investments and maintain current reserve margin levels.

There are a number of factors that contribute to the relatively higher energy margins in Alberta (at current reserve margins) compared to ERCOT (at the target reserve margin), including: (1) ERCOT's unusually flat supply stack that results in relatively infrequent price spikes and lower infra-marginal revenues compared to other markets, as explained in Section I.D.2; (2) higher ancillary services revenues in Alberta, particularly for combustion turbines; and (3) Alberta's more permissive approach to market mitigation that contributes to higher energy prices and margins during peak times. A more thorough analysis of the Alberta market is available in the market review we conducted for the AESO.[4]

<u>TIEC Question No. 5</u>

Referring to p.7: Please state what Brattle believes to be the strike price of the majority of existing price-responsive demand in ERCOT.

<u>Brattle Group Response</u>:

We have not examined this question. However, *existing* price-responsive demand must have strike prices at a range of levels below the existing offer cap. (If the strike price were higher, the end-user would not respond to prices and would therefore not be classified as "existing" price-responsive demand.)

<u>TIEC Question No. 6</u>

Referring to p.7: Please identify all mechanisms or market features that create scarcity pricing in ERCOT during non-scarcity conditions, as defined in the report.

<u>Brattle Group Response</u>:

1. Setting prices based on the PBPC during transient shortage conditions caused by ramp limitations among units that are committed but not fully dispatched. Such conditions are just as likely to occur when the system has a very high reserve margin as when the system has a modest or low reserve margin.

2. Dispatching ONRUC capacity at the SWOC even if the ONRUC capacity was committed to meet real-time demand, e.g., after a unit has tripped offline. Again, these types of events are just as likely to result in high scarcity prices when the system has a high reserve margin as when it has a modest or low reserve margin.

3. Releasing responsive reserves to SCED at the SWOC raises price prematurely if the responsive reserve requirement is higher than needed for operational reasons. It would be

[4] See: http://www.brattle.com/_documents/UploadLibrary/Upload943.pdf

more appropriate to set reserves requirements based on actual system need rather than artificially inflating these requirements in order to introduce scarcity prices more often.

TIEC Question No. 7

Referring to p.10, fn. 8: Brattle notes that a "hotter `normal` weather profile was used to produce ERCOT's load forecast, which decreased the reserve margin calculation.

A. Does Brattle agree with using this profile?
B. How does Brattle recommend weather-normalizing the load forecast?
C. Does Brattle agree that the industry standard for normal weather to use 30 years of data?
D. How many years of data do other RTOs use to produce their load forecast?

Brattle Group Response:

A. We have not analyzed this question.

B. See answer to Question 13.B below.

C. We have not done a survey of all regions' approaches.

D. We have not done a survey of all regions' approaches.

TIEC Question No. 8

Referring to p.11: What evidence did Brattle review or rely upon to determine that ERCOT has historically used a 1-in-10 LOLEV? Is Brattle aware of when ERCOT adopted this standard?

Brattle Group Response:

We confirmed this via conversations with the ERCOT staff who conduct the relevant LOLE studies. According to ERCOT staff, ERCOT adopted the 1-in-10 Loss of Load Events target with the reserve margin study finalized in January 2007.[5]

TIEC Question No. 9

Referring to p. 51: Please provide the calculations referenced in the paragraph at the bottom of p. 51 comparing forward prices to CONE.

[5] See the 2007 study here: http://www.ercot.com/content/meetings/gatf/keydocs/2007/20070112-GATF/ERCOT_Reserve_Margin_Analysis_Report.pdf
See also the 2010 reserve margin study:
http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

Brattle Group Response:

These calculations are based on futures price data purchased from Platts which cannot be distributed (although they may be purchased directly from Platts).

TIEC Question No. 10

Referring to p.53: The report references "low-cost, short lead-time investments such as uprates and reactivations" that have already been attracted by the market. Please identify what uprates or reactivations Brattle expects before 2014 and the total capacity these developments will provide.

Brattle Group Response:

Apart from the additions that have been publicly announced, we can only speculate. See ERCOT's CDR report or Section III.D of our report to confirm those additions that have been publicly announced.

TIEC Question No. 11

Referring to p.55: Please provide the output of the LOLE model for each of the 15 years of weather data.

Brattle Group Response:

This inquiry should be directed to ERCOT staff, who are currently working to update their LOLE modeling efforts.

TIEC Question No. 12

Referring to p.55., fn.116: The report references a "1,700 MW load over-forecast error during super-peak periods which reduces the incidences of load shedding and scarcity events." Please describe the 1700 MW over-forecast error in the load forecast greater detail. Is this error still present in ERCOT's forecast?

Brattle Group Response:

The observed 1,700 MW error refers to the difference between ERCOT's load forecast and actual realized load at the peak in August 2011, when prices were at the $3,000 cap. ERCOT's load forecast resulted in a peak demand of 70,049 MW, compared to an actual peak demand of 68,379 MW. Discussions with ERCOT staff indicated that the load forecast likely was overstated because the load forecast model does not account for price responsive demand, 4CP response, voluntary public response to conservation appeals, and other model error. Until the load forecast adds these factors as variables, we expect that load forecasts will continue to be overstated on average during super-peak conditions.

TIEC Question No. 13

Referring to p.56: In the notes to Figure 18, Brattle states that "ERCOT's current weather normalization methodology places its weather-normalized peak for 2012 substantially above the mean and median peak loads corresponding to the last 15 years' weather profiles imposed on a 2012 economy.

A. Why is ERCOT's current weather normalization methodology above both the mean and the median of the last 15 years of weather?
B. What does Brattle believe should be the methodology—the mean, the median, or something else?
C. Is this difference the same as the 1700 MW over-forecast error, or are these separate issues? Please explain.

Brattle Group Response:

A. Our understanding is that ERCOT's weather normalization methodology produces an annual peak load that exceeds the median peak load because it is based on the median *annual* peak-day weather (among all weather years considered) and an assumption that in a normal year such weather would be most likely to occur in August. Focusing the peak weather on August increases the peak load above the median peak load. This is because the load model translates a given one-day weather profile into higher loads in August than in other months because of the multi-day heat-island effect, among other factors.

B. There are several weather-normalization methodologies, and we have not evaluated their relative strengths and weaknesses within the ERCOT context, although other reviews of this sort have been conducted elsewhere.[6] However, it is important to note that ERCOT's weather normalization methodology does not affect the amount of capacity needed to meet a given level of reliability (unless ERCOT changes its weather normalization methodology without correspondingly changing the required reserve margin target percentage). The amount of capacity needed to meet a given level of reliability is estimated using the LOLE model, and can be expressed equivalently as either a large percentage of a relatively low weather-normalized peak or a smaller percentage of a relatively high weather-normalized peak.

C. This is a different issue. Over-forecast error during super-peak conditions would tend to cause the LOLE model to overstate load shedding, unless an adjustment is made for the error, as we did in our analysis. See answer to Question 12.

TIEC Question No. 14

Referring to p.57, fn. 119: The report references a 1700 MW correction to ERCOT's load forecast, but states in a footnote that this is likely an under-correction. What correction does the Brattle Group believe would be appropriate and unbiased?

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[6] See, for example, Hanser, Phil. (2012) "Weather Normalization of Electricity Sales," *The Brattle Group.* EEI Forecasting Website. March 30, 2012.

Brattle Group Response:

We do not have a precise estimate. A roughly 2,500 MW correction would make our 2011 backcast of the frequency of scarcity events more closely match the realized levels, but we have not determined why such a large correction would be needed. Possibilities include: (a) differences in generation availability between actual 2011 conditions and those simulated stochastically in the model; (b) differences between the conditions that actually trigger scarcity pricing and our representations of those conditions based on the LOLE model; and (c) other factors influencing the accuracy of the LOLE model. Therefore, we do not know whether a different adjustment would be more appropriate for our going-forward analysis. However, we address the possibility that a larger adjustment might be more accurate in our sensitivity analysis represented as "other modeling uncertainties" on pages 68-70.

TIEC Question No. 15

Referring to p.58: Brattle states that it adjusted scarcity pricing patterns observed in 2011 to account for the fact that 500 MW was moved from Non-Spinning Reserve Service (NSRS) to Responsive Reserve Service (RRS) by shifting the distribution in Figure 20 to the right. Please answer the following in relation to this adjustment:

A. Did Brattle calculate the average impact in $/MWH of the 500 mw shift?
B. If so, what is the impact?
C. If not, please provide the underlying data in native format.

Brattle Group Response:

A. No.

B. Not applicable.

C. After determining a historical relationship between "residual capacity" and scarcity pricing, we used that relationship to estimate the likelihood of experiencing scarcity prices at each level of residual capacity observed in the LOLE model. With the 500 MW shift, we project that scarcity would be observed 500 MW sooner.

TIEC Question No. 16

Referring to p.61: Did Brattle backcast its non-scarcity margins (Fig. 24) for actual market outcomes in ERCOT for 2008-2011? Please provide any underlying data and results for this time period or any portion of it.

Brattle Group Response:

Results of our non-scarcity backcast for 2008-2011 are shown in Figure 23. This figure compares actual historical average non-scarcity market heat rates to a backcast result based on our regression and historical hourly reserve margins. Regression-predicted heat rates are slightly lower than actuals in 2010, and slightly higher than actuals in 2008, 2009, and 2011.

TIEC Question No. 17

Referring to p.61: The adders for non-scarcity margins used for Non-Spin Reserve Service (NSRS) offer floors and the RUC price floor added $2000 per MW-year of Peaker Net Margin in the Brattle study. However, the ERCOT backcast for 2011 filed with the PUC shows that recent protocol changes had an impact of $25,000 per MW-year. Please explain why Brattle did not use the ERCOT backcast for the impact of these recent protocol changes and identify the reasons for any discrepancies.

Brattle Group Response:

ERCOT's 2011 backcast included a number of factors that would not have been appropriate to add to our estimates. One was the impact of increasing RRS requirements and the RRS price floor. We accounted for these changes directly in our model, as explained in Section IV.A. Adding ERCOT's backcast-based estimates to ours would have double-counted the effect.

We also excluded ERCOT's estimated impact of the RUC price floor on peaker net margins. Our analysis projects the energy margins for a GE7FA-based simple-cycle combustion turbine, which is not likely sufficiently flexible to capture most of these price events since they generally occur over very brief intervals (a fact we confirmed using ERCOT's backcast). However, we also examined the alternative possibility that these units might be able to capture all or a portion of the incremental RUC floor impact and found that it did not significantly change our results, as explained on page 62.

TIEC Question No. 18

Referring to p.62: Brattle claims that both Combined Cycle Gas Turbines (CCGT) and Simple Cycle Gas Turbines (SCGT) are likely economic in long-term equilibrium. Please explain the basis for and assumptions underlying this statement.

Brattle Group Response:

This statement recognizes the widely-understood planning and market principle that a downward-sloping load duration curve can be met most economically through a mix of baseload (low variable cost, high fixed cost), intermediate (medium variable cost, medium fixed cost), and peaking (high variable cost, low fixed cost) generation. One type of generation might be most economic at any point in time, but if that type is favored for long enough, eventually the mix returns to balance and the other types also become economic.[7]

[7] For example, see Section III.A of http://www.brattle.com/_documents/UploadLibrary/Upload807.pdf

TIEC Question No. 19

Referring to p.63: ERCOT's backcast for 2011 shows a PNM of $150,000 with a $3000 price cap and a nominal 14% reserve margin. Yet Brattle shows that such of level of PNM would not be reached unless reserve margin were close to 16%. Please explain the discrepancy.

Brattle Group Response:

We developed our analysis largely independently of ERCOT's backcast and would not expect the two separate approaches to produce the same results. First, there are some elements of PNM that we deliberately exclude, as explained above. Second, our simulations are not a backcast but rather are based on a large number of trials from the ERCOT LOLE model representing a range of potential outcomes under a particular planning reserve margin and weather profile. ERCOT's backcast represents one potential outcome with respect to outages, load, and wind under that weather profile and planning reserve margin.

TIEC Question No. 20

Referring to p.63: For the 2011 curve in Figure 25 how much of the CT Energy Margin was due to scarcity in the summer months vs. scarcity in February?

Brattle Group Response:

Almost all scarcity is in the summer months. The LOLE model assumes typical generation outage patterns that do not account for the freezing of equipment that actually occurred in February 2011.

TIEC Question No. 21

Referring to p.63: Please explain why the report assumes that 2011 weather would have a 1-in-15 chance of occurring when the report elsewhere notes that it was the hottest summer since 1895, which would make 2011 weather a 1-in-116-years occurrence? Please describe how Brattle believes such anomalous weather should be addressed in creating a weather-normalized load forecast.

Brattle Group Response:

We do not have an opinion about the appropriate weight for 2011 weather. We show the implications of different probability weightings on page 67, including an estimate with a 1-in-100 chance of 2011 weather. Developing an appropriate weight for planning purposes would involve determining whether long-term trends exist in the weather patterns.

TIEC Question No. 22

Referring to p.67: Brattle notes that the extremes of 2011 weather are a "major reason why reliance on scarcity prices is unlikely to achieve ERCOT's current reliability objective." Given that 2011 represented 1-in-100-year weather, does Brattle believe that it appropriate for electric systems to plan for 1-in-100 year weather? Please explain.

Brattle Group Response:

That depends on the reliability objectives. The current objectives are statistically based and are highly affected by the tails of the distributions, including the weight that ERCOT judges should be placed on the likelihood of 2011 weather re-occurring. If policy makers were to determine that rolling outages were acceptable under very extreme weather conditions that might be viewed as "an act of God," the planning criteria could be adjusted accordingly.

TIEC Question No. 23

Referring to p.72-80: Please list the recent changes at ERCOT which Brattle believes lead to inefficiently high prices, and any estimates or data relating to the price impacts of each.

Brattle Group Response:

See responses to question 6. ERCOT has analyzed the price impacts of these changes in its backcasting analyses.

TIEC Question No. 24

Referring to p.78: Please explain how revisiting credit and qualification provisions for REPs will mitigate the risk/incentive for a REP to exploit asymmetric risk. Does Brattle believe that its recommendation increase the cost of entry for REPs and favor established REPs with large numbers of existing customers and affiliated generation? If not, why not?

Brattle Group Response:

We have not examined these issues in detail. We only identified a risk and recommended that the PUCT assess whether additional measures are warranted to avoid such risks.

TIEC Question No. 25

Referring to p.81: Has Brattle estimated the price impacts that would result from adopting all of the marginal cost-based pricing recommendations from Table 16 in lieu of the current market design? Please provide any relevant calculations or conclusions.

Brattle Group Response:

We have not evaluated this question.

TIEC Question No. 26

Referring to p.82: The report states that "The PNM is an imperfect measures because actual peaking generators are able to earn only 60-85% of PNM due to imperfect dispatch and various operating costs." Please provide all calculations and any supporting data that support this 60%-85% estimate.

Brattle Group Response:

This is based on a comparison between the IMM's CT Net Revenue Estimates and the realized PNM as administratively calculated for the purposes of determining whether to implement the Low System Offer Cap. The comparison over years 2008-11 is shown in the following table, with sources listed in fn. 162 of our report.

Year	IMM CT Net Revenue *($/kW-y)*	Peaker Net Margin *($/kW-y)*	Actual Net Revenue as Fraction of PNM *(%)*
2008	$60	$100	60%
2009	$30	$45	67%
2010	$45	$53	85%
2011	$105	$125	84%

TIEC Question No. 27

Referring to p.87: Please state whether new entry in Alberta is from existing generators who have market power, or by unaffiliated new entrants. Please provide any data supporting your answer.

Brattle Group Response:

A substantial portion of new generation online or under construction since 2000 has been developed by incumbents as shown in the following table. According to current holdings as summarized on a summer installed capacity basis, TransAlta, ATCO, and Capital Power own 38.8%, 15.0%, and 13.3% respectively of all capacity in Alberta, with the remaining 28.5% market share held by entities with less than 5% market share. Of the 5,125 MW of new generation that has come online since 2000 or is currently under construction, 2,383 MW, or just under half, is owned by incumbents with more than 5% market share. The remaining 2,743 MW are owned by smaller entities with less than 5% market share.

We also provide a few important caveats for interpreting these data. First, the current owner of these assets may not be the original developer; we have not attempted to identify the original developer of each plant. Second, the market share as reported below does not translate directly into what the Alberta Market Surveillance Administrator (MSA) refers to as "Offer Control." A substantial minority of the existing Alberta power plants are under long-term power purchase agreements (PPAs) that provide the buyer the ability to offer the associated power supplies into the market. These PPAs cover assets that existed prior to market restructuring and their associated power supplies were auctioned off in order to increase market competitiveness.[8] The entities identified by the MSA as having more than 5% offer control in 2012 own 3,386 MW of built or under construction since 2000 (66% of the total). Finally, provincial regulations and MSA guidelines impose a cap of 30% on the total offer control share that any one entity can hold in Alberta. This limit is a key component of the market monitoring and mitigation framework in Alberta.[9] However, the limit is not currently binding, with the highest offer control share in 2012 being held by TransCanada with 18.4%.[10]

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8 For a discussion of these PPAs and reference to detailed descriptions of the process by which they were developed, see Section III.B here: http://www.brattle.com/_documents/UploadLibrary/Upload943.pdf See also the MSA evaluation of market share offer control in 2012 here: http://albertamsa.ca/uploads/pdf/Archive/2012/Market%20Share%20Offer%20Control%202012.pdf

9 See Section 3.2.4 here: http://albertamsa.ca/uploads/pdf/Consultations/Market%20Participant%20Offer%20Behaviour/Decide%20-%20Step%205/Offer%20Behaviour%20Enforcement%20Guidelines%20011411.pdf

10 See p. 3 here: http://albertamsa.ca/uploads/pdf/Archive/2012/Market%20Share%20Offer%20Control%202012.pdf

Company	Owned Assets		Market Share
	All (MW)	Built Since 2000 (MW)	(%)
TransAlta Corp.	4,842	1,234	38.8%
ATCO Power	1,869	444	15.0%
Capital Power	1,654	705	13.3%
Enmax Corp.	601	601	4.8%
Syncrude Canada, Ltd.	435	80	3.5%
TransCanada Corp.	403	403	3.2%
The City of Medicine Hat	273	137	2.2%
EnCana	234	234	1.9%
Suncor Energy, Inc.	183	119	1.5%
Dow Chemical Co.	180	-	1.4%
Imperial Oil, Ltd.	180	180	1.4%
Nexen, Inc.	174	174	1.4%
Maxim Power Corp.	142	1	1.1%
Air Liquide Group	127	-	1.0%
Alberta Pacific Forest Industries, Inc.	99	99	0.8%
Meg Energy Corp.	94	94	0.8%
Nova Corp.	93	-	0.7%
Greengate Power Corp.	88	88	0.7%
Constellation Energy Group.	85	85	0.7%
Opti Canada, Inc.	85	85	0.7%
NextEra Energy, Inc.	82	82	0.7%
Others with <0.5% Market Share	547	282	4.4%
Total	12,468	5,125	100%

Sources and Notes:
Data summarized from Ventyx Energy Velocity Suite.
Quantities reported on a summer installed capacity basis with no derating for wind.

<u>TIEC Question No. 28</u>

Referring to p.101: Please list all system operators besides ERCOT who use the “1 outage event in ten years” as their reliability standard.

<u>Brattle Group Response</u>:

A North American Electric Reliability Corporation (NERC) review from 2008 indicated that the “1 event in ten years” standard was used to determine the reserve margin requirement by NYISO, PJM, and MISO. A number of other entities also calculate the 1 event in 10 years metric as one component of their reliability assessments, including ISO-NE, Maritimes, Ontario, and Quebec.[11] Other entities calculated a different metric such as 1 day of outages in 10 years, 0.1 days per year, or base the reserve margin on a different type of reliability or cost-benefit analysis.

TIEC Question No. 29

Referring to p.101: What is the specific normalized Expected Unserved Energy (EUE) adopted by the NERC Task Force? If this standard were applied to ERCOT, what reserve margin would this suggest?

Brattle Group Response:

The metric we referred to in our report as the Normalized EUE would be calculated for an individual calendar year as:[12]

Normalized EUE = [EUE/(Net Energy for Load simulated)] x 1,000,000

The reserve margin resulting from using this metric would have to be calculated by ERCOT staff in their LOLE modeling efforts.

TIEC Question No. 30

Referring to p.102: Residential VOLL is generally considered to be less than $5,000/MWh. Given this, why has Brattle recommend a SWOC of $9,000? Was this number intended as an example of a potential VOLL estimate, or is it intended as an actual price cap recommendation? Please explain.

Brattle Group Response:

Not all customers are residential; commercial and industrial customers tend to have much higher VOLL. See response to question 3.

[11] Note that the full details of each entity's reserve margin calculation are not always reported and would have to be determined by directly examining those regions' approaches. Further, some entities' methodologies have changed since this time. See http://www.nerc.com/docs/pc/ris/NERC_Res_Adeq_Criteria_Inventory_080130.xls

[12] See Appendix 3, Section B.3.c here: http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf

Luminant Energy Company LLC's (Luminant) Technical Questions for the Brattle Group

Luminant Question No. 1

On p. 72, you define "scarcity conditions" as "those hours when administrative interventions are required in response to capacity shortages, and where a contributing cause of the capacity shortage is a low planning or realized reserve margin." On p. 75, you state that "During scarcity conditions, as during normal conditions, the efficient market price will reflect the marginal system cost of power. Ideally, it would be best to rely on high-priced DR curtailment bids (or offers, if DR is included on the supply side) to set prices in scarcity conditions." On p. 80, you recommend introducing scarcity prices gradually through a scarcity pricing curve that starts at $500/MWh when first depleting operating reserves. a. Please explain how you calculated $500/MWh as the marginal system cost of power for depleting operating reserves. b. If you believe that $500/MWh is a reasonable proxy for "high-priced DR curtailment bids," please explain how you derived that value.

Brattle Group Response:

A. We did not specify $500/MWh based on a calculation of the marginal cost of depleting operating reserves, but simply referenced that level as a reasonable proxy that is likely above the marginal cost of the highest-cost generating resources. However, we *do* recommend conducting an estimate of the costs of depleting operating reserves in order to inform: (a) whether $500/MWh or some other price level would be the most appropriate starting point for such a curve; and (b) the appropriate shape of that curve. The marginal cost of depleting operating reserves will be subject to substantial uncertainty and may change with system conditions, so it may be appropriate to use a simplified proxy formula that is generally informed by a quantitative analysis.

B. We did not state that $500/MWh is a reasonable proxy for DR curtailment bids, but rather, we anticipate that many DR curtailment bids would come in at a range of costs, many of which may be far above $500/MWh. We do, however, believe that if substantial DR curtailment bids were to be incorporated into the market, a large number of them would likely be within the range from $500/MWh to the price cap (the range we proposed for an administrative scarcity pricing function).

Luminant Question No. 2

On p. 96, you indicate that one of the purposes of the scarcity pricing curve that you have described is"so that DR that is not in SCED can respond to prices without depressing prices to levels far below their willingness-to-pay." On p. 12, you indicate that the range of VoLL is approximately $3,000 - $12,000 (supplemented by footnote 14 that explains that estimates of VoLL vary widely and that a MISO study found ranges of $1,500/MWh to $80,000/MWh). In further discussing VoLL and this MISO study on p. 77 you indicate that "MISO set its price cap at the low end of $3,000/MWh, consistent with Residential VoLL estimates. Please describe how a scarcity pricing curve that starts at $500/MWh, rather than $3,000/MWh will meet the goal of allowing passive demand response.

Brattle Group Response:

The $3,000-$12,000 VOLL range quoted would apply only to *involuntary* load shed imposed on an average customer. “Passive” demand response is voluntary and will presumably be provided by the subset of loads with the least marginal value, starting below the average value of involuntarily shed load.

Luminant Question No. 3

On p. 80, you state that "a more continuous scarcity pricing approach" will allow non-price-setting demand to contribute to price formation even if is not incorporated into SCED, because it can reduce consumption without causing prices to plummet. a. Please explain why a sudden reduction in demand will not cause prices to plummet, even if a scarcity pricing curve exists. b. Do you believe that a scarcity pricing curve will reduce incentives for load to participate actively by making offers in SCED once that functionality is available?

Brattle Group Response:

A. A sudden reduction in demand would reduce prices. However, if prices change along a gradual curve instead of a single, large step function, the price impact will likely be reduced. Moreover, the price stability associated with a gradual curve should better enable price-responsive loads to adjust their consumption to the concurrent spot price. This is more likely to result in a price equal to loads’ willingness to pay.

B. No. Any high prices will incent passive response. Only a subset of customers are likely to be interested in participating in SCED. Customers are likely to participate directly in SCED only if they can satisfy all of the requirements for setting prices and if they value being in SCED (and better coordinating their load decisions with the actual real-time price) in excess of setup costs and the costs of potential imbalance charges.

Luminant Question No. 4

Are any other markets currently using a scarcity pricing curve similar to the one you recommend? a. If yes, are they energy-only markets? b. If yes, for each market, how large is the curve as a percentage of the annual peak load?

Brattle Group Response:

Yes.

A. We are not aware of any energy-only markets that have yet implemented such a curve. Markets that have developed graduated administrative scarcity pricing curves include MISO, CAISO, PJM, NYISO, and ISO-NE. Some of these curves are gradual functions that increase to the price cap, while others are blockier mechanisms. In fact, all U.S. RTOs other than ERCOT have recently been required to evaluate their pricing algorithms during times of operating reserves shortages in response to FERC Order 719.

B. We have not calculated the percentage for each RTO but agree that it would be useful to survey the details of other RTOs' administrative scarcity pricing approaches.

<u>Luminant Question No. 5</u>

On p. 89 you state: "ERCOT does not admit load reductions to offer and be paid as energy supply in either the day ahead or real-time markets," and on p. 97 you state: "Other demand resources are already efficiently accommodated through the day-ahead energy market." Please explain your view of how demand response participates in the day-ahead market.

<u>Brattle Group Response:</u>

Loads are allowed to submit price-responsive demand bids in the day-ahead market but not the real-time market currently. Some day-ahead bids may correspond to price-based load reductions; others may be used to hedge price exposure between procuring power in day-ahead and real-time markets.

<u>Luminant Question No. 6</u>

On pp. 96-97, you indicate that deploying emergency demand response at its strike price, at or near the price cap, is needed for large amounts of demand response to contribute to efficient price setting in the real-time market, and reference NPRR 444 as the proposed solution to accomplish this (p. 97 n. 202). Is it a fair interpretation of your statements that deploying emergency demand response without first implementing NPRR 444 will cause inappropriate market impacts?

<u>Brattle Group Response:</u>

Brattle has not fully evaluated NPRR 444 and may not support all of the concepts in the NPRR, such as the 0-to-LSL. However, during periods when emergency loads are deployed, prices should reflect the system conditions. ERCOT should consider adding the load response into SCED or administratively accounting for the load response in the scarcity pricing mechanism.

<u>Luminant Question No. 7</u>

On p. 99, you state that your "simulations indicate that at the highest price caps, a gradually sloped scarcity pricing curve beginning at $500/MWh and rising linearly to the price cap just before shedding load would reduce the equilibrium planning reserve margin by roughly two percentage points relative to the current scarcity pricing function. Please describe these calculations.

Brattle Group Response:

To simulate a gradually sloped scarcity pricing curve, we replaced the scarcity pricing and residual capacity patterns derived from the current scarcity pricing function (as explained in Section IV.D.1) with a scarcity pricing function that begins at $500/MWh and slopes linearly to the price cap at zero MW of residual capacity. This contrasts with the existing scarcity pricing function, which reaches the price cap quite quickly. Because of this difference, energy prices reach the full price cap less frequently with a gradual scarcity pricing function, which drives down energy margins and decreases the economic equilibrium reserve margin relative to the current scarcity function with the same price cap.