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AEP ENERGY PARTNERS' APPEAL OF THE DECISION OF THE ERCOT BOARD ASSIGNING OKLAUNION GENERATING STATION TO THE WEST ZONE AND REQUEST FOR EXPEDITED CONSIDERATION AND EMERGENCY REMAND WITH INSTRUCTIONS	§ § § § § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

AEP ENERGY PARTNERS' APPEAL OF THE DECISION OF THE ERCOT BOARD ASSIGNING OKLAUNION GENERATING STATION TO THE WEST ZONE AND REQUEST FOR EXPEDITED CONSIDERATION AND EMERGENCY REMAND WITH INSTRUCTIONS

NOW COMES AEP Energy Partners and files this Appeal of the Decision of the Electric Reliability Council of Texas ("ERCOT") Board regarding the Board's Approval of 2009 Commercially Significant Constraints ("CSCs"), Transmission Congestion Zones, Closely Related Elements ("CREs"), and Boundary Generation Resources in the ERCOT transmission system, which assigned the Oklaunion Generating Station ("Oklaunion") to the West Congestion Zone, and its request for expedited consideration and emergency remand with instructions to the ERCOT Board, and in support thereof would respectfully show as follows:

I.
IDENTITY OF PARTIES

AEP Energy Partners is the complainant; it is a power marketer that operates in ERCOT. AEP Energy Partners packages diversified resources for resale to wholesale customers, primarily municipalities and cooperatives. It currently has a contract for the output from AEP Texas North Company's share of Oklaunion.

AEP Energy Partners estimates that the monetary loss it will suffer as a result of the ERCOT Board decision at issue in this Appeal, which decision placed Oklaunion in the West Congestion Zone versus the North Congestion Zone for 2009, is in the range of $35 million to $45 million per year, assuming natural gas prices in the range of $7.10 to $9.50/mmbtu. Because, for the reasons hereinafter described, this loss is entirely attributable to lost sales of power that consumers in the North Congestion Zone would otherwise find attractive, the estimated loss represents not just a loss to AEP, but a very significant and substantial loss of consumer benefit. Accordingly, those affected by the decision at issue in this appeal include AEP Energy Partners as well as consumers of power in the North Congestion Zone.

The names, mailing addresses, telephone numbers and email addresses of AEP Energy Partners' authorized representatives for service of all pleadings and documents are as follows:

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ERCOT is the Respondent in this proceeding. The name, mailing address, telephone and facsimile numbers and email address for ERCOT's authorized representative is believed to be as follows:

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II.
STATEMENT OF THE CASE

(i) The Underlying Proceeding. The ERCOT Board voted on October 21, 2008 to approve the 2009 CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources in the ERCOT transmission system, which decision is based on a load-flow study known as "Scenario 3i."[1] This Appeal of the Board's approval of Scenario 3i is timely filed within 35 days of the date of the ERCOT conduct complained of, in accordance with P.U.C. PROC. R. 22.251(d).

(ii) The Entities or Classes of Entities Who Would be Directly or Indirectly Affected by the Commission's Decision. The ERCOT Board's approval of Scenario 3i directly affects AEP Energy Partners.[2] AEP Energy Partners has an interest in half of the output (approximately 350 MW) of Oklaunion, which will be clustered in the West Congestion Zone, instead of the North Congestion Zone, under Scenario 3i.[3] The decision also indirectly affects the generators and loads in the West and North Congestion Zones, as hereinafter more particularly described.

(iii) Description of the Conduct from Which AEP Energy Partners Seeks Relief and Statement of the ERCOT Procedures, Protocols, By-laws, Articles of Incorporation, or Law Applicable to Resolution of the Dispute. The ERCOT transmission grid, including generation resources and loads, is divided into several congestion zones that are determined on an annual basis. Pursuant to ERCOT Protocols Section 7, "Congestion Management," each congestion zone is defined such that every generator or load within the congestion boundaries has a similar effect on the transmission facilities that limit transfer between congestion zones.[4] Those transmission facilities are called CSCs. ERCOT reassesses CSCs annually based on changes of the system topology – that is, changes in the electric infrastructure and loads within ERCOT. New congestion zones, characterized by movements of generation and load from one zone to another, may be identified based on the reassessed CSCs.

The conduct complained of resulted from the Technical Advisory Committee's ("TAC") and the ERCOT Board's application of Section 7.2 of the ERCOT Protocols, which establishes

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[1] *See* Attached Exhibit 1 at page 15 (Minutes of ERCOT Board Meeting, October 21, 2008). Unless otherwise indicated, all the documents attached to this Appeal are public documents available on the ERCOT website, www.ercot.com, as attested to in the attached affidavit. Appellant was informed by ERCOT's counsel that, since ERCOT is not a governmental body, it does not issue certified copies of its records. Accordingly, Appellant requests that the attached affidavit be accepted in lieu of ERCOT's certification. In the alternative, Appellant urges the Commission's presiding officer to determine that the attached documents are the appropriate subject of official notice under P.U.C. PROC. R. 22.222 and to waive the certification requirement found in P.U.C. PROC. R. 22.251(d)(1)(H).

[2] The decision also directly affects the North HVDC tie and a small amount of load, which under Scenario 3i remain in the West Congestion Zone.

[3] The other participants who share in the output from Oklaunion are not affected by this dispute because they either export their share of electricity to the Southwest Power Pool or have pre-assigned transmission congestion rights.

[4] ERCOT Protocols Section 7.1. Attached as Exhibit 2 is a copy of Section 7 of the ERCOT Protocols.

the CSC Zone determinations process. The process, as applied by ERCOT this year, resulted in the approval of Scenario 3i — a scenario whereby several generators were moved from the West to the North Congestion Zone, but not Oklaunion. Another scenario, "Scenario 3h," would have moved all of the foregoing generators to the North Congestion Zone, plus Oklaunion as well.

AEP Energy Partners has great respect for ERCOT Staff and the ERCOT Board. Without exception, the individuals on the Board (and members of ERCOT Staff) serve with honor and distinction, and nothing said in this Appeal should be interpreted as a challenge to the motivations or professional conduct of these individuals. AEP Energy Partners believes, however, that, in this instance, the ERCOT Staff and Board were incorrect in the process and analysis they used to determine the zone to which Oklaunion was assigned. Had the ERCOT Staff and Board followed the procedures and analysis that have been established and followed in applying and interpreting Section 7.2 of the ERCOT Protocols in previous cases, Scenario 3h would and should have been approved.

(iv) Compliance with ADR Procedures. For the reasons stated in Section VII., AEP Energy Partners requests waiver of the ADR Procedures described in P.U.C. Proc. R. 22.251(c).

(v) Suspension of Board Decision. P.U.C. Proc. R. 22.251(i) requires that the Appellant demonstrate good cause if it seeks to suspend the conduct or implementation of the decision complained of while the appeal is pending at the Commission. AEP Energy Partners does not seek suspension of the ERCOT Board's decision while this Appeal is pending at the Commission.

AEP Energy Partners respectfully requests, however, that the Commission consider this matter on an expedited basis pursuant to P.U.C. Proc. R. 22.251(k). The implementation of the 2009 CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources will occur on January 1, 2009. Although the holiday season is fast approaching, AEP Energy Partners requests that the Commission consider this case at its December 18, 2008 Open Meeting and, if it agrees that Scenario 3i should be reconsidered or rejected for the reasons herein enumerated, that this proceeding be remanded to the ERCOT Board and TAC with instructions that the ERCOT Board make a new determination, based on analyses that were conducted in accordance with past procedures and application of the ERCOT Protocols, before the end of this year, 2008, or as soon as possible thereafter. Ensuring that any reversal of the ERCOT Board's decision would occur before other market participants conduct transactions based on the current decision constitutes good cause for processing this matter on an expedited basis. AEP Energy Partners is unaware whether its request for expedited consideration will be opposed. Attached as Appendix A is a proposed procedural schedule in accordance with P.U.C. PROC. R. 22.251(k)(1).

(vi) Basis for Commission Jurisdiction. The Commission has jurisdiction over this matter pursuant to PURA §§ 39.001(c) and 39.151(a)(1) and P.U.C. PROC. R. 22.361(b) (prohibiting discrimination against market participants). The Commission further has jurisdiction under P.U.C. PROC. R. 22.251 (governing the procedures for review of ERCOT actions).

III.
STATEMENT OF THE ISSUES

(1) Whether the ERCOT Board's approval of the 2009 CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources in the ERCOT transmission system should have been based on Scenario 3h, which utilized the previously established procedures and a rigorous and objective, steady-state modeling analysis that has been uniformly applied in similar circumstances, rather than Scenario 3i, which applied a different and previously unused post-contingency analysis relying on conjecture and subjective, unverifiable considerations.

(2) Whether the ERCOT Board's approval of the 2009 CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources in the ERCOT transmission system, based on a scenario, Scenario 3i, that selectively applied a different and previously unused post-contingency analysis, will appropriately balance market participant interests.

(3) Whether it is just and reasonable to impose congestion management responsibilities, and the economic consequences thereof, on one solid-fuel facility, Oklaunion, or whether instead, and especially in light of ERCOT Protocols Section 7.2.4 and the consumer benefits of Scenario 3h, it is just and reasonable to adopt Scenario 3h, which would place Oklaunion in the North Congestion Zone.

IV.
STATEMENT OF FACTS

As reflected in Section 7.1 of the ERCOT Protocols, ERCOT manages transmission congestion costs by employing a zonal congestion scheme that is "flow based," whereby the ERCOT grid, including the attached resources and loads, is divided into a number of congestion management zones based on a process for determining CSCs and CREs that is set forth in the Protocols and guided by previous ERCOT practices and procedures.[5] In this way, the ERCOT Protocols serve to minimize transmission congestion costs while balancing the competitive and consumer interests of all market participants.

The proper congestion management zones can and do change from time to time based on changes in system topology, and so, each year for the past eight years, the ERCOT Staff has conducted analyses that are ultimately used by TAC and the ERCOT Board to determine the upcoming year's CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources pursuant to ERCOT Protocols Section 7.2.[6]

For determining the ERCOT Congestion Zones, the first step in the process involves identifying candidate CSCs.[7] The CSCs are the specific transmission elements that are identified to represent and manage power transfer limitations between regions of the State. ERCOT Protocol Section 7.2.1 establishes the process for determining CSCs.

The next step involves the clustering of generators and loads that have similar impacts on the CSCs ("clustering").[8] ERCOT Protocols Section 7.2.2 establishes the process and procedures for clustering of generation and loads. In performing both the identification of CSCs and the clustering of generation and loads analyses, the ERCOT Staff has always used, and the resulting ERCOT Board's determinations have always utilized, the latest "Steady State Working Group Data Set A summer peak case" as the load-flow model.[9] The steady-state model that ERCOT uses for determining CSCs, as required by Section 7.2.1(1) of the ERCOT Protocols, assumes a fully-intact transmission system; that is, no transmission facilities are assumed to be out of service. It is not a post-contingency analysis. In the past, the same load-flow model identified above and in ERCOT Protocol Section 7.2.1 (*i.e.*, the Steady State Working Group Data Set summer peak case) has been used as the basis for the clustering analysis.

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5 *See generally* Ross Baldick and Hui Niu, *Lessons Learned: The Texas Experience in Electricity Deregulation: Choices and Challenges*, Ch. 4, at page 195 et seq. (James M. Griffin and Steven L. Puller ed. 2005), available for viewing at: http://books.google.com/books?id=9n29ItGH-24C&printsec=frontcover#PPA195,M1.

6 Protocols Section 7.2 states: "By November 1 of each year, the appropriate ERCOT subcommittee will report to the TAC and ERCOT Board with recommended CSC designations, resulting Congestion Zone boundaries with any granted exemptions noted, CRE designations and associated Boundary Generation Resources for ERCOT Board review and approval."

7 ERCOT Protocols § 7.2.1(1)(a).

8 ERCOT Protocols § 7.2.2.

9 ERCOT Protocols § 7.2.1(1).

The next steps in the process provide for identifying CREs, Boundary Generation Resources, and Average Zonal Shift Factors. ERCOT Protocols Sections 7.2.3 and 7.2.4 establish the process and procedures for determining CREs, Boundary Generation Resources and Average Zonal Shift Factors.

The ERCOT Protocols provide that the appropriate ERCOT Technical Advisory Committee Subcommittee will review the results and process that the ERCOT Staff used to determine the Congestion Zones to be recommended for approval to the TAC and the ERCOT Board. Thus, the established process that has resulted in prior years' designations of CSCs and Transmission Congestion Zones requires that the ERCOT Staff's analyses first be vetted and analyzed by the Congestion Management Working Group ("CMWG"), which considers the options and makes recommendations to the Wholesale Market Subcommittee ("WMS"). The WMS then considers the options and makes recommendations to TAC, which in turn considers the options and makes a recommendation to the ERCOT Board.

This year, the results of ERCOT Staff's analyses were considered by CMWG at meetings on July 11, July 22, and August 1, 2008. CMWG did not reach unanimous consensus on the proposed CSCs and Transmission Congestion Zones for 2009,[10] so, on August 1, CMWG approved three scenarios for consideration by WMS: Scenarios 3b, 3g, and 3h. Each of those scenarios proposed five CSCs for 2009 and four Transmission Congestions Zones.[11] The CSCs for 2009 changed from prior years due to the completion of the Long Creek substation, which unloaded the traditional CSCs that had been used in determining the Transmission Congestion Zones for 2008.

Following a meeting on August 20, 2008, WMS recommended Scenario 3h to TAC for recommendation to the ERCOT Board.[12] Under Scenario 3h, Oklaunion would be clustered in the North Congestion Zone.

However, two business days before the TAC meeting on September 4, 2008, an entirely new fourth Scenario emerged: Scenario 3i, which was not among the scenarios ERCOT Staff presented to CMWG or WMS for review. Under Scenario 3i, Oklaunion would be clustered in the West Congestion Zone. While not having been first analyzed and vetted by CMWG or

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[10] *See* September 9, 2008 memo to ERCOT Board from TAC, Exhibit 3 at page 1.

[11] *Id.* at 1-2.

[12] *Id.* at 2.

WMS, as ERCOT Protocol Rule 7.2.2 specifically contemplates, Scenario 3i was approved by TAC, which recommended its adoption to the ERCOT Board.[13]

On September 16, 2008, the ERCOT Board, in light of procedural concerns, remanded the proceeding back to TAC to reexamine Scenarios 3b, 3h, and 3i.[14] A joint TAC/WMS meeting convened on October 8, 2008 to consider the scenarios and make a recommendation to the ERCOT Board. At that meeting, ERCOT Staff confirmed that there were no reliability concerns respecting Scenario 3h, and that it could operate the system under Scenario 3h. ERCOT Staff confirmed further that there would be sufficient generation in the West Congestion Zone under Scenario 3h (with Oklaunion in the North Congestion Zone) to resolve zonal congestion in the West Zone. WMS and TAC, however, nonetheless recommended approval of Scenario 3i.[15]

Because Oklaunion is a coal-fired unit, in every year prior to this year when conducting the analysis to determine CREs, ERCOT had excluded Oklaunion from the list of units likely to vary their output consistent with Section 7.2.4 of the ERCOT Protocols. ERCOT Protocols Section 7.2.4, titled "Determining Generation Resources Deemed Likely to Vary Their Output," states that, at the beginning of the year, ERCOT will compile a list of all generation resources fueled by nuclear fuel, coal or lignite, and exclude such resources from the calculation of Zonal Shift Factors. This year, however, contrary to Section 7.2.4, ERCOT treated Oklaunion as movable, or likely to vary its output, for purposes of the CRE selection process. No other coal-fired unit in Texas was similarly treated.

AEP appealed the TAC decision.[16] The ERCOT Board then approved Scenario 3i on October 21, 2008.[17]

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[13] *Id.* at 3-4.

[14] October 10, 2008 memo from TAC to ERCOT Board, Exhibit 4 at page 1.

[15] *Id.* at 1-3.

[16] A copy of that appeal is attached and incorporated herein for all purposes as Exhibit 5.

[17] Minutes of ERCOT Board Meeting, October 21, 2008, Exhibit 1 at page 15.

V.
ARGUMENT

1. **The ERCOT Board Should Have Adopted Scenario 3h for Determining Congestion Management Zones for 2009, Because Scenario 3h, Unlike Scenario 3i, is Fully Consistent with the ERCOT Protocols and the Process and Manner of Analysis That ERCOT Has Used Previously in Determining Zonal Congestion Management Boundaries.**

There is no dispute that ERCOT Staff used the Steady State Working Group 2009 Data Set A 2009 summer peak base case in determining the 2009 CSCs.[18] This the ERCOT Protocols clearly and explicitly require. The second-step clustering analysis, however, that resulted in Scenario 3i, involved a significant, unprecedented variance from past procedures.[19]

In the past, the ERCOT Staff has always used the same Steady State Working Group Data Set A identified in ERCOT Protocol 7.2.1. in performing the clustering analysis. That analysis is based on a **fully-intact** transmission system. However, unlike every other clustering analysis performed for every Congestion Zone in this case, and in all prior years' cases, the ERCOT Staff altered the Steady State Working Group Data Set A and performed a post-contingency clustering analysis involving only the Oklaunion-Fisher Road/Fisher Road-Bowman 345-kV line ("Bowman Line") for Scenario 3i.[20] In other words, the ERCOT Staff's Scenario 3i clustering analysis assumed that the Bowman Line was out of operation — that the transmission system was not intact. That analysis resulted in Oklaunion being clustered in the West Congestion Zone instead of the North Congestion Zone, as would have been the case under Scenario 3h.

AEP Energy Partners has three fundamental concerns with the departure from the steady-state analysis used in prior cases. First, it appears that the unprecedented change in clustering methodology lacks objective justification. The ERCOT Staff has confirmed that there were no reliability concerns with Scenario 3h (WMS's original recommendation), and that it could

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18 *See* September 3, 2008 ERCOT CSC Study Proposals, version 3.3, Exhibit 6 at page 1.

19 The difference in the outcome of the analyses between Scenario 3h and Scenario 3i is that, with the exception of the North HVDC tie and a small amount of load, only Oklaunion was moved from the North Congestion Zone to the West Congestion Zone.

20 *Compare* ERCOT 2009 CSC Study Proposals, version 3.2, dated August 13, 2008, Exhibit 7, at page 5, with ERCOT 2009 CSC Study Proposals, version 3.3, dated September 3, 2008, Exhibit 6, at page 5. In version 3.3, Scenario 3i appears for the first time, and it is the only cluster analysis marked as a post-contingency analysis.

operate the transmission system under Scenario 3h.[21] Further, the ERCOT Staff confirmed that there would be sufficient generation in the West Congestion Zone under Scenario 3h (without Oklaunion in the West Zone) to resolve zonal congestion.[22] While there was some conjecture about how Scenario 3h versus 3i might affect such market elements as Out Of Merit Energy/Uplift costs, zonal prices, PCR values, and TCR revenues, those elements were not and cannot be quantified. Accordingly, such conjecture should not provide a sufficient basis for departing from the usual and customary application of the ERCOT Protocols and procedures. Scenario 3h is therefore the only appropriate solution remaining at this time.

Second, there is also insufficient justification for performing the post-contingency analysis in just one of the four Congestion Zones and on just one of the five CSCs, which primarily affected Oklaunion. All of the other CSCs were studied on a pre-contingency basis, consistent with past practice and procedure. While the ERCOT staff did indicate that it believed Scenario 3i gave it the best tools to manage congestion in a cost effective manner, there was no indication that the ERCOT Staff ever previously applied the same post-contingency standard for analyzing this issue or that the ERCOT Staff had considered this standard in connection with any of the other CSCs or Congestion Zones. Rather, by all appearances, the clustering analysis for the West Congestion Zone was singled out for the application of a post-contingency analysis. As explained below, if ERCOT desires to use post-contingency analyses in the clustering process, post-contingency analyses should be utilized from the beginning, across-the-board, and in a manner that all the stake-holders and subcommittees have the opportunity to fully vet and review. It should not be implemented in an *ad hoc* fashion after the majority of the process has transpired. Furthermore, if post-contingency analyses are utilized, they should be performed on all the CSCs and in all the Congestion Zones, not just selectively in one Congestion Zone and one CSC.

Third, if ERCOT desires to consider post-contingency analyses in the future, it should do so at the beginning of the process, in a transparent and an even-handed manner, and in a manner that tests all contingencies. It should also, as a minimum, clarify the ERCOT Protocols so that all market participants will know and understand the possibility of ERCOT's departing from a steady-state analysis, in favor of a subjective and complex contingency analysis. As it occurred

21 October 8, 2008 Minutes of the Joint Emergency Technical Advisory Committee and Wholesale Market Subcommittee Meeting, Exhibit 8, at page 5.

22 *Id.*

in this case, the post-contingency analysis was performed *after* the ERCOT Staff's usual and customary studies were considered by CMWG, and *after* WMS made its recommendation to TAC, and *contrary* to the analysis contemplated in the ERCOT Protocols and initially used by the ERCOT Staff this year, last year and in all prior years.[23] While the ERCOT Board did remand the issue for more study, the post-contingency analysis was still applied selectively in a manner that afforded Oklaunion less favorable access to the transmission grid.

2. Scenario 3h Will Likely Improve Consumer Welfare in the North Congestion Zone as Compared to Scenario 3i, and Will Likely Have a Negligible Impact on Consumer Welfare in the West Congestion Zone.

Scenario 3i impacts Oklaunion from both the perspective of AEP Energy Partners, as a seller, and also the perspective of customers that would benefit from access to a coal-fired power plant. As a result of being clustered in the West Congestion Zone, Oklaunion cannot make deliveries into the North Congestion Zone on the same basis as it would if it were properly clustered in the North Congestion Zone under Scenario 3h. Because of the depressed energy prices in the West Congestion Zone resulting primarily from the abundance of wind generation and limited transmission, AEP Energy Partners estimates that the monetary loss it will suffer from Oklaunion being erroneously placed in the West Congestion Zone versus the North Congestion Zone is approximately $35 million to $45 million per year.[24] Thus, the unprecedented application of the clustering analysis in this matter is not insignificant.

Furthermore, by placing Oklaunion in the West Congestion Zone, potential customers in the North Congestion Zone will have reduced access to Oklaunion's output because of the inter-zonal congestion costs that would be assigned in moving power from the West Congestion Zone to the North Congestion Zone. In comparison to the West Congestion Zone, where for many hours of the year the Market Clearing Price of Energy is negative (as determined by ERCOT), the North Congestion Zone has much less low-cost generation in relation to the load. The consumers in the West Congestion Zone do not benefit from Oklaunion's presence there, as prices will remain low in the West Congestion Zone regardless of where Oklaunion is clustered.

23 Although arguably not at issue in that decision, it should be noted that a post-contingency analysis was not used in the decision for 2008 CSCs, Transmission Congestion Zones, and CREs, which resulted in the movement of the South Texas Nuclear Plant to the Houston Congestion Zone.

24 There is currently a $15 to 20/MWh spread between electricity prices in the North Congestion Zone versus prices in the West Congestion Zone. $15 times 8760 times 344 MW from Oklaunion times 75% capacity factor equals approximately $35 million, and $20 times 8760 times 344 times 75% equals approximately $45 million.

AEP Energy Partners submits that the unusual and uncustomary post-contingency analysis was unjustified and is detrimental to consumer welfare in both the North and West Congestion Zones.[25] Scenario 3i should be rejected.

3. The Result of Scenario 3i is Not Just and Reasonable for AEP Energy Partners.

The $35 million to $45 million loss that AEP Energy Partners will suffer as a result of the adoption of Scenario 3i represents an estimate of the sum of the lost sales that would be made in the North Congestion Zone had Scenario 3h been adopted. The subjective and conjectural analysis supporting Scenario 3i was based on anecdotal, unsupported and unqualified concerns about the possibility of uplift costs. There was no effort to compare such subjective considerations to the uplift costs expected in connection with Scenario 3i and no effort whatsoever to consider the impact to AEP Energy Partners and to consumers of power in the North Congestion Zone.

The real benefit to keeping Oklaunion in the West Congestion Zone, if the anecdotal and conjectural comments at the TAC meeting are to be credited with any weight, which they should not, is that under Scenario 3i, Oklaunion would likely operate in a manner never intended for a coal unit, as evidenced by ERCOT Protocol Section 7.2.4. That is, the unit will be "forced" to vary its output and, in this way, manage congestion that should managed by other resources in the West Congestion Zone. ERCOT Protocol 7.2.4 provides:

> At the beginning of each year, ERCOT will compile a list of all Generation Resources fueled by nuclear fuel, coal or lignite. ERCOT will exclude such units from the calculation of Zonal Shift Factors for the rest of the year. All other Generation Resources will be deemed likely to vary their output.

In every year prior to this year, because Oklaunion is a coal-fired unit, it has been excluded from the list of units likely to vary their output. This year, however, ERCOT treated Oklaunion as movable, or likely to vary its output, for purposes of the CRE selection process. No other coal-fired unit was similarly treated.

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[25] From a legal perspective, the ERCOT decision amounts to discriminatory treatment that is prohibited by PURA § 39.001(c), which provides that "[r]egulatory authorities ... may not make rules or issue orders regulating competitive electric services, prices, or competitors or restricting or conditioning competition except as authorized in this title and may not discriminate against any participant or type of participant during the transition to a competitive market and in the competitive market." Similarly, ERCOT Protocol 1.2 states: "In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, nondiscriminatory manner."

The fact that Oklaunion was treated differently than other generators is also the reason that AEP Energy Partners is the only market participant objecting to the ERCOT Board's decision at this time; it is the only market participant that is directly and adversely affected by the decision. It is neither just nor reasonable to single out Oklaunion in this manner. Public Policy should not deny AEP Energy Partners and consumers in the North Congestion Zone the substantial benefits that would be realized if Oklaunion were properly clustered in the North Congestion Zone.

VI.
QUESTIONS OF FACT FOR EVIDENTIARY HEARING

At this time AEP Energy Partners believes that the dispute only involves a determination of whether the unprecedented application of the post-contingency clustering analysis, particularly at such a late time, and the unprecedented designation of Oklaunion as a movable unit, were justified.[26] AEP Energy Partners does not believe that the timing of events and the nature of the application of the ERCOT Protocols and procedures are in dispute, so it should be possible to stipulate to the pertinent facts. However, AEP Energy Partners reserves the right to supplement this statement should ERCOT's response or subsequent discovery reveal disputed factual issues.

VII.
GOOD CAUSE EXISTS TO WAIVE REQUIREMENT TO USE ERCOT ALTERNATIVE DISPUTE RESOLUTION ("ADR")

There are a number of reasons for waiver of ERCOT's ADR process. First, the issues presented here have already been aired at ERCOT. This is a request for review of an ERCOT Board decision that came after AEP's presentation before the ERCOT Board challenging the selection of Scenario 3i by TAC. Second, the dispute over this determination is not a private, one-on-one dispute between AEP Energy Partners and ERCOT, but rather, as stated herein, it could have implications for a number of other market participants. Consequently, it is not the type of dispute that lends itself to an ADR process. Third, because of the imminent approach of the implementation of the ERCOT decision, on January 1, 2009, there is not time to pursue ADR, especially given the ERCOT's Board recent consideration of this matter suggests that there is little likelihood that ERCOT would change its position. Finally, and perhaps most

[26] Such selective and unprecedented treatment of the West Congestion Zone that results in the disparate treatment for Oklaunion violates PURA's prohibition against discriminatory treatment of market participants.

importantly, counsel for AEP Energy Partners contacted counsel for ERCOT, and he indicated that this is not the type of dispute that has been subject to the ADR process in the past, that ERCOT Staff would feel compelled to follow the Board's decision that has already been made, and that they "will not argue that AEP should have gone to ADR before appealing the ERCOT Board's decision to the PUCT."

VIII.
REQUEST FOR EXPEDITED CONSIDERATION

AEP Energy Partners requests that the time limits provided in P.U.C. PROC. R. 22.251 be shortened as indicated in the attached procedural schedule, and that the Commission consider this case on an expedited basis without referral to the State Office of Administrative Hearings. The facts should not be in dispute. This case simply calls for a determination of whether the ERCOT Board's decision adopting Scenario 3i should be reconsidered or rejected, thereby avoiding the imposition of severe harm on AEP Energy Partners as well as improving the general welfare. Although the holiday season will occur in the midst of the proposed procedural schedule, AEP Energy Partners requests that the Commission consider this case at its December 18, 2008 Open Meeting and, if it agrees that Scenario 3i should be reconsidered or rejected, that this proceeding be remanded to the ERCOT Board and TAC with instructions that the ERCOT Board make a new determination, based solely on analyses that were conducted in accordance with past procedures and application of the ERCOT Protocols, before the end of this year, 2008, or as soon as possible thereafter. Alternatively, AEP Energy Partners requests that the Commission determine that Scenario 3i should be rejected and that Scenario 3h be approved in its place. If this matter is not completely resolved by the end of the year, or very soon thereafter, AEP Energy Partners will suffer irreparable harm. Furthermore, there may be other unknown and unquantifiable affects on other market participants if the ERCOT Board's decision were unwound long after the beginning of 2009.

IX.
NOTICE

In conjunction with the expedited consideration requested above, AEP Energy Partners requests that the 14-day notice period provided in P.U.C. PROC. R. 22.251(e) be shortened to fit within the proposed procedural schedule. Pursuant to that schedule, ERCOT would provide notice, in the manner described in Rule 22.251(e), of this Appeal by Monday, November 24, 2008.

X.
CONCLUSION

Based on the foregoing, AEP Energy Partners requests that the Commission enter an Order granting its Appeal, finding that TAC's and the ERCOT Board's approval of Scenario 3i was not justified because Scenario 3i resulted from a late, unprecedented analysis under the ERCOT Protocols and established procedure. Accordingly, AEP Energy Partners requests that the Commission remand this proceeding to the ERCOT Board and TAC on an emergency basis with instructions that TAC and the ERCOT Board reconsider the decision on 2009 CSCs, Transmission Congestion Zones, CREs, and Boundary Generation Resources based solely on analyses that were conducted in accordance with past procedures and application of the ERCOT Protocols. On remand, the ERCOT Board should be further instructed to make its determination by December 31, 2008 or as soon as possible thereafter. In the alternative, AEP Energy Partners requests that the Commission order that the ERCOT Board adopt Scenario 3h for the 2009 calendar year as that Scenario was approved by CMWG and WMS under application of the established ERCOT Protocols and procedures.

AEP Energy Partners additionally requests that the Commission consider its request on an expedited basis such that this Appeal can be resolved by the December 18, 2008 Open Meeting. AEP Energy Partners further requests the Commission award any and all such further relief to which it may be entitled.

Respectfully submitted,

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By: Scott Olson
ATTORNEYS FOR AEP ENERGY PARTNERS

CERTIFICATE OF SERVICE

I hereby certify that on the 19th day of November, 2008, a true and correct copy of the foregoing has been transmitted by electronic mail, U.S. mail and/or hand-delivery to all parties.

Scott Olson

Scott Olson

AFFIDAVIT

STATE OF OKLAHOMA §
COUNTY OF TULSA §

Before me, the undersigned, on this day personally appeared C. Richard Ross, having been duly sworn, upon oath states as follows:

1. My name is C. Richard Ross and my business address is 6705 E. 81^{st} Street, Suite 160, Tulsa OK, 74133.

2. I am of legal age and a resident of the State of Oklahoma.

3. I am submitting this Affidavit in support of AEP's Appeal of the Decision of the Electric Reliability Council of Texas Board's Approval of 2009 Commercially Significant, Constraints, Transmission Congestion Zones, Closely Related Elements, and Boundary Generation Resources in the ERCOT transmission system.

4. The Exhibits that are attached to the Appeal and marked as obtained from ERCOT's website were obtained by me from ERCOT's website, www.ercot.com. Each such Exhibit attached thereto is a true and correct copy of the document available from ERCOT's website.

5. The facts stated in the foregoing Appeal are, in my opinion and based on my experience in this matter, true and correct.

FURTHER, AFFIANT SAYETH NOT.

C. Richard Ross

C. Richard Ross

Subscribed and sworn to before me, the undersigned notary public, by the said C. Richard Ross, on this 18th day of November, 2008.

Anna M. Zaragoza

Notary Public

(NOTARY SEAL)

ANNA M ZARAGOZA
My Commission Expires
April 25, 2010

APPENDIX A

Proposed Procedural Schedule

ERCOT serves notice[1]	Monday, November 24, 2008
ERCOT response[2]	Friday, December 5, 2008
Motion to Intervene and associated response[3]	Monday, December 8, 2008
PUCT Staff response[4]	Tuesday December 9, 2008
Company reply[5]	Thursday, December 11, 2008
Open Meeting	Thursday, December 18, 2008

[1] P.U.C. Proc. R. 22.251(e).
[2] P.U.C. Proc. R. 22.251(f).
[3] P.U.C. Proc. R. 22.251(g).
[4] P.U.C. Proc. R. 22.251(g).
[5] P.U.C. Proc. R. 22.251(h).

DRAFT MINUTES OF THE BOARD OF DIRECTORS MEETING OF ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Electric Reliability Council of Texas, Inc.
7620 Metro Center Drive, Room 206
October 21, 2008 at 10:00 a.m.

Pursuant to notice duly given, the meeting of the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) convened on the above-referenced date.

Meeting Attendance:

Board Members:

Director	Affiliation	Segment
Armentrout, Mark		Unaffiliated, Chair
Ballard, Don	OPC	Consumer/Residential and Small Commercial
Cox, Brad	Tenaska Power Services	Independent Power Marketer; Proxy to Jean Ryall after lunch
Dalton, Andrew	Valero Energy Corp.	Consumer/Industrial
Espinosa, Miguel		Unaffiliated (attended until Agenda Item 16)
Fehrenbach, Nick	City of Dallas	Consumer/Commercial (by proxy to Andrew Dalton at Agenda Item 15.d. for remainder of meeting)
Gent, Michehl		Unaffiliated, Vice Chair
Helton, Bob	IPA	Independent Generator (by proxy to Mark Walker at Agenda Item 7 until Agenda Item 15.d.)
Jenkins, Charles	Oncor Electric Delivery	Investor-Owned Utility
Kahn, Bob	ERCOT	ERCOT
Karnei, Clifton	Brazos Electric Coop.	Cooperative (by proxy to Dan Wilkerson at Agenda Item 15 for remainder of meeting)
Newton, Jan		Unaffiliated
Patton, A.D.		Unaffiliated
Smitherman, Barry T.	Chairman	Public Utility Commission of Texas
Thomas, Robert	Green Mountain Energy	Independent Retail Electric Provider (by proxy to Marcie Zlotnik at Agenda Item 15 for remainder of meeting)
Wilkerson, Dan	Bryan Texas Utilities	Municipal

Staff and Guests:

Abernathy, Rick	Eagle Energy Partners
Adib, Parviz	APX
Anderson, Kenneth	Public Utility Commission of Texas
Ashley, Kristy	Exelon
Barry, Victor	Texas RE
Bartley, Steve	CPS Energy
Bell, D.	WCTMWD
Bell, Wendell	TPPA
Benedict, Nathan	OPC
Brandt, Adrianne	Austin Energy
Brewster, Chris	City of Eastland
Brown, Jeff	Shell
Bruce, Mark	FPL Energy
Byone, Steve	ERCOT
Capezzuti, Nancy	ERCOT
Clemenhagen, Barbara	Topaz Power
Cochran, Seth	RBS Sempra
Comstock, Read	Direct Energy
Crowder, Calvin	AEP Service Corp.
Crozier, Richard	Brownsville
Day, Betty	ERCOT
Deskins, Andy	Wachovia Bank
Doggett, Trip	ERCOT
Dohrwardt, Bray	Direct Energy
Dreyfus, Mark	Austin Energy
Dumas, John	ERCOT
Firestone, Joel	Direct Energy
Forfia, David	ERCOT
Fox, Kip	AEP
Garrity, Tom	Siemens
Goff, Eric	Reliant
Grable, Mike	ERCOT
Grendel, Steve	ERCOT
Gurley, Larry	Luminant
Haas, Jason	Public Utility Commission of Texas
Harrell, Katherine	Third Planet
Hayslip, Darrell	EON
Hinsley, Ron	ERCOT
Hobbs, Kristi	ERCOT
Jones, Dan	Potomac Economics
Jones, Dan	Reliant
Jones, Liz	Oncor
Jones, Randy	Calpine

King, Kelso	King Energy
Leady, Vickie	ERCOT
McMurray, Mark	Direct Energy
McRae, Russ	Areva
Moore, John	EON
Morris, Sandy	LCRA
Moss, Steven	First Choice Power
Nelson, Donna	Public Utility Commission of Texas
Oldham, P.	TIEC
Rexrode, Caryn	Customized Energy Solutions
Ried, Walter	Wind Coalition
Roark, Dottie	ERCOT
Ross, Richard	AEP
Rowe, Evan	Public Utility Commission of Texas
Ryall, Jean	Constellation Energy
Saathoff, Kent	ERCOT
Sanders, Sheri	OPC
Schafer, Matt	FPLE
Seely, Chad	ERCOT
Seymour, Cesar	SUEZ
Soutter, Mark	Invenergy
Spears, Clay	Signal Hill
Steckleih, Chris	Direct Energy
Stephenson, Ronda	Luminant
Troutman, Jennifer	AEP
Troxtell, David	ERCOT
Vincent, Susan	Texas RE
Wagner, Marguerite	PSEG Texas
Walker, DeAnn	CenterPoint Energy
Walker, Mark	NRG Texas
Wattles, Paul	ERCOT
Weston, Tisa	ERCOT
Wittmeyer, Bob	DME
Wullenjohn, Bill	ERCOT
Yager, Cheryl	ERCOT
Yoho, Lisa	Citigroup Energy
Zion, Mark	TPPA
Zlotnik, Marcie	StarTex

Call to Order General Session (Agenda Item No. 1)

Mark Armentrout, Chairman, called the Meeting of the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) to order at 10:12 a.m. Barry T. Smitherman, Public Utility Commission of Texas (PUCT) Chairman, called to order an open meeting of the PUCT.

Mr. Armentrout reminded the Board that, while credit and Nodal issues are important, the primary business of ERCOT is to maintain reliability, run markets, and ensure open access to the grid. These duties require good, hard work by ERCOT staff, and he asked ERCOT management to thank their staff on behalf of the Board for their hard work.

Consent Agenda (Agenda Item No. 2)
Mr. Armentrout noted that all items on the Consent Agenda had been removed for discussion or revision.

Chairman Smitherman then remarked that it does not appear that the three PUCT Commissioners can attend the Question and Answer (Q&A) sessions held the day before the Board Meeting, and even though no Board actions are taken at Q&A sessions, he is interested in finding a way for all three Commissioners to participate. He advised that he is communicating with the Attorney General's Office on this topic.

At this time, Mr. Armentrout reminded the Board and attendees of the Antitrust Admonition that was displayed on the screen in the meeting room.

Approval of Minutes (Agenda Item No. 3)
Mr. Armentrout noted that there were two edits to be made to the various sets of minutes presented to the Board for approval. Mike Grable, ERCOT Vice President and General Counsel, noted that on page four of the August 28, 2008 Board Meeting Minutes, A.D. Patton requested that "regression software" be changed to "regression analysis." Mr. Grable further noted that on the September 16, 2008 Board Meeting Minutes, Brad Cox asked that it be noted that he stepped out of the Board Meeting for the Technical Advisory Committee (TAC) Report and that his Segment Alternate, Jean Ryall, sat in his place for that item only.

Jan Newton moved to approve the September 16, 2008 Board Meeting Minutes as amended. The motion was seconded by Bob Kahn. The motion passed by unanimous voice vote with no abstentions.

Ms. Newton moved to approve the September 23, 2008 Board Meeting Minutes. The motion was seconded by Miguel Espinosa. The motion passed by voice vote with three abstentions (Bob Kahn, Don Ballard and Nick Fehrenbach).

Michehl Gent moved to approve the August 28, 2008 Board Meeting Minutes as amended. The motion was seconded by Mr. Fehrenbach. The motion passed by voice vote with one abstention (Charles Jenkins).

CEO Report (Agenda Item No. 4)
Bob Kahn, ERCOT President and Chief Executive Officer (CEO), reported on the recently completed North American Electric Reliability Corporation (NERC) audit. He explained that ERCOT anticipated receiving and responding to a draft audit report soon, and would keep the Board fully informed.

He also reported on his recent trip with Chairman Armentrout to attend NERC's Cyber Security Summit meeting in Washington, D.C. on September 23, 2008. The conference focused on known and emerging cyber security issues. He said that NERC wanted to raise the profile of cyber security and anticipated that there will be more from NERC and the Federal Energy Regulatory Commission (FERC) on that topic.

Operating Reports (Agenda Item No. 5)
The following Operating Reports were presented to the Board.

Financial Summary (Agenda Item No. 5.a.)
The Board had no questions or comments at that time.

Investment Update (Agenda Item No. 5.a., continued)
Steve Byone, ERCOT Vice President and Chief Financial Officer (CFO), provided the Investment Management Update presentation, previously distributed to the Board for their review, on ERCOT's current investment status. Mr. Byone discussed the purpose of ERCOT investing activity, the management and oversight of investing activity, the recent events impacting investments, and next steps. Mr. Grable added that, while Mr. Byone correctly described the history of ERCOT's interactions with The Reserve regarding priority of redemption requests, it would now be up to the U.S. Securities and Exchange Commission (SEC) to decide the process by which redemptions would be paid.

Don Ballard inquired about the reasoning for having all money-market funds in one investment company. Mr. Byone replied that the Investment Standard calls for variety among the investments themselves, and both Reserve funds in which ERCOT was invested held a variety of investments. However, ERCOT will now look at establishing a concentration limit per fund, and Mr. Byone reported that, currently, ERCOT is using two money managers until ERCOT has an updated Investment Standard.

Michehl Gent, Vice Chairman, asked if the SEC was going to allow The Reserve to delay payouts of ERCOT's funds. Mr. Byone replied that he could not predict the SEC's actions, but that some fund investments would not be fully mature for up to a year. Mr. Gent further inquired if The Reserve outsourced their accounting. Mr. Byone replied that he did not know.

Market Operations Report (Agenda Item No. 5.b.)
Trip Doggett, ERCOT Executive Vice President and Chief Operating Officer, commented that he had received questions regarding slides 16 and 17 in the presentation. He advised that from this point forward he will remove slide 16 if there were no objections. None of the Board members objected to this proposed change in format.

IT Report (Agenda Item No. 5.c.)
The Board had no questions or comments at that time.

Grid Operations Report (Agenda Item No. 5.d.)
Andrew Dalton asked about the wind forecasting noted on page five of the presentation. Kent Saathoff, ERCOT Vice President of System Operations, responded that August was a difficult

month for wind and load forecasting. He pointed out that August had very unusual weather, such as one tropical storm and one hurricane. He further pointed out that wind forecasting is still in its early stages and the model is being trained.

System Planning Report (Agenda Item No. 5.e.)

The Board had no questions or comments at that time.

Nodal Update (Agenda Item No. 6)

Ron Hinsley, ERCOT Vice President and Chief Information Officer, provided an update, via presentation, on the Nodal Program.

Chairman Smitherman noted that there is currently not a Nodal schedule in place. He asked how ERCOT is able to track progress. Mr. Hinsley replied that ERCOT is using internal benchmarking despite the absence of a fully developed and agreed schedule.

Mr. Gent said that the Board placed great emphasis on holding the Nodal Protocol Revision Requests (NPRRs) that were not directly related to the Nodal Program. He asked if ERCOT was still following that practice. Mr. Hinsley responded affirmatively. Chairman Armentrout asked if ERCOT is using the new process of proposing NPRRs. Mr. Kahn stated that any NPRRs that go before the Board for approval have been approved by him first.

Chairman Armentrout asked, as the PUCT reviews the plan to evaluate the costs of the Nodal Program, when ERCOT believes that they will announce to the market the new Nodal schedule. Mr. Grable stated that he did not think ERCOT staff could answer that as there will be no ERCOT-developed schedule until the PUCT-led Cost-Benefit Analysis is complete.

Mr. Hinsley introduced Thomas Garrity of Siemens Energy Inc. (Siemens), who provided the Board with a presentation on the Network Model Management System.

Chairman Smitherman asked Mr. Garrity if other Independent System Operators (ISOs) were pursing the same best-of-breed approach as ERCOT or were going with commercial-off-the-shelf (COTS) systems, and further asked about delays or cost overruns. Mr. Garrity replied that in his experience, the predominant approach worldwide has been to go with a single vendor, although he felt that the conventional wisdom that this means reduced risk is not necessarily true, because it means long-term reliance on a single vendor, limiting flexibility and options. He added that best-of-breed is more demanding and challenging up-front, but he believed that it was the best solution in the long run. He further explained that in the United States and Canada the current thinking is to go with best-of-breed components. He commented that the United Kingdom is generating a new system that would suggest they are going toward 'best of breed' also. He mentioned that as far as development projections, those that have gone into production have blown away all budgets and cost estimates and are evaluating whether they have received all functionality.

Chairman Smitherman asked if the California Independent System Operator (CAISO) is the closest comparison to ERCOT in this instance. Mr. Garrity replied affirmatively and noted that CAISO is significantly behind schedule.

Ms. Newton asked whether, integration aside, ERCOT faces other key risks. Mr. Garrity replied that ensuring that ERCOT and all vendors create agreed common data, and further agree on how it will be transferred and translated, is a key risk. A.D. Patton asked whether integration issues could have been addressed earlier. Mr. Garrity responded that he could answer the historical question, but stated that all vendors know now how all of the systems work together and knew how to get the program working.

Chairman Smitherman stated his concern that ERCOT is building a prototype and asked Mr. Garrity if it will work, and also whether it might become obsolete by the time it goes live. Mr. Garrity responded that there are risks to being on the leading edge but that they are known and are not insurmountable, and that ERCOT and the vendors have clear vision of how to complete the Nodal program. He added that ERCOT was guarding against obsolescence by incorporating new technology as it is developed.

For scheduling reasons, the Agenda Items were taken out of order at this time.

Special Nodal Program Committee Report (Agenda Item Nos. 11 and 11.a.)
Bob Helton, Special Nodal Program Committee (Nodal Committee) Chair, provided a brief update on the first meeting of the Nodal Committee. Mr. Helton reported that the Committee took the lessons learned so far in the Nodal Program and particularly in Internal Audit's review of third-party oversight of the Nodal Program to date, and incorporated those lessons into a Request for Proposal (RFP) for a third-party vendor and in the Nodal Committee Charter. He said that the Nodal Committee would make a recommendation to the Board on the RFP in the Executive Session of the Meeting.

He further advised that the Nodal Committee recommended to the Board that it adopt the Nodal Committee Charter, as amended at the Nodal Committee Meeting. **Mr. Gent moved to approve the Nodal Committee Charter, as amended at the Nodal Committee Meeting. Clifton Karnei seconded the motion. The motion passed by unanimous voice vote with no abstentions.**

Last, Mr. Helton provided the Board with the final list of the Nodal Committee members. They are: Bob Helton (Chair), Miguel Espinosa, Nick Fehrenbach, A.D. Patton, Robert Thomas, Jean Ryall (Vice Chair) and Steve Bartley. Mr. Helton also reminded the Board members and attendees that everyone can attend the Nodal Committee meetings.

Human Resources & Governance Committee Report (Agenda Item Nos. 10, 10.a. and 10.b.)
Jan Newton, Chair of the Human Resources and Governance (HR&G) Committee, provided a brief update on the HR&G Committee. She reported that Bill Wullenjohn, ERCOT Director of Internal Audit, provided an overview of the IBM Nodal Reassessment Report to the HR&G Committee, but that the HR&G Committee was very supportive of the creation of the Nodal Committee and that the Nodal Committee would directly oversee further Nodal Program issues. Don Ballard, Public Counsel, added that the Committee discussed ERCOT Internal Audit's role in Nodal oversight and that Internal Audit will monitor the third-party reviewer along with the Nodal Committee.

Ms. Newton noted that the HR&G Committee had finalized their response to the PUCT regarding the R.W. Beck Study and that ERCOT staff is preparing a letter summarizing the Board's views.

Ms. Newton also reported that the HR&G Committee unanimously favored looking into broadcasting future Board meetings via the Internet, and that the Committee asked ERCOT staff to get more information on specific vendor proposals.

Mr. Grable discussed the Board Policies and Procedures and reminded the Board that ERCOT needed an approved appeal procedure; he also requested that the Board delegate to ERCOT staff the task of updating the Policies and Procedures to reflect the Unaffiliated Director Compensation changes that were approved at the September 16, 2008 Board meeting. **Ms. Newton moved to approve the Board Policies and Procedures, as discussed. Mr. Dalton seconded the motion. The motion passed by unanimous voice vote with no abstentions.**

Ms. Newton advised that the HR&G Committee also reviewed the HR&G Committee Charter and proposed two revisions, both to reflect the Committee's role on compensation matters. **Ms. Newton moved to approve the HR&G Committee Charter, as amended. Mr. Dalton seconded the motion. The motion passed by unanimous voice vote with no abstentions.** Finally, Ms. Newton commented that the HR&G Committee briefly discussed the current unprecedented financial and market conditions, and expressed that the Committee felt satisfied that there was adequate Board governance regarding these conditions.

Finance & Audit Committee Report (Agenda Item Nos. 9, 9.a. and 9.b.)
Clifton Karnei, Finance and Audit Committee (F&A Committee) Chair, reported the F&A Committee reviewed ERCOT's nepotism policy and believes it is appropriate.

He advised that the F&A Committee had reviewed the Internal Audit status report, recent EthicsPoint submissions, and the risk-based 2009 Internal Audit Plan, and further that the Committee agreed it is appropriate for Internal Audit to perform renewable-energy audits of Market Participants and increase its staffing from seven to eight. Mr. Karnei also reported that the F&A Committee met with Mr. Wullenjohn as Chief Audit Executive in Executive Session for a quarterly private meeting.

Mr. Karnei mentioned ERCOT's need for additional debt financing to meet current and projected obligations, which would be discussed in Executive Session.

He noted that the F&A Committee reviewed ERCOT's debt, received a liquidity update, reviewed quarterly investment results, and met with PricewaterhouseCoopers (PWC) regarding the 2009 financial audit plan. He further mentioned that the F&A Committee is not recommending approval on the revised standard form guarantee today, but rather is going to remand the form to the Credit Work Group (CWG) to review the form and request specific reasons why the guarantee form recommended by outside counsel and supplied by ERCOT Legal was not used.

Mr. Karnei advised that the F&A Committee recommended that the Board reaffirm the current F&A Committee Charter without any changes. Don Ballard stated that he would not oppose the Charter but that he continues to believe that the F&A Committee should be separated into two committees. **Mr. Karnei moved to reaffirm the F&A Committee Charter. Mr. Jenkins seconded the motion. The motion passed by unanimous voice vote with no abstentions.**

Mr. Byone informed the Board that a revised 2009 budget was scheduled for presentation in December, and that if it slips into January a one-month budget for January 2009 would be presented in December, at a minimum.

Lunch (Agenda Item No. 8.)
The meeting broke for lunch.

TAC Report (Agenda Item Nos. 7, 7.a.-7.e.)
Mark Dreyfus, TAC Chair, provided the Board with the TAC Report.

Mr. Dreyfus reported that TAC met to consider the following Protocol Revision Requests (PRRs):

PRR765 – Time of Use Revisions [Profiling Working Group (PWG)]. Proposed effective date: November 1, 2008. No budgetary impact; no additional full-time equivalents (FTEs) needed; no system changes required; existing business processes can accommodate this PRR; no impact to grid operations. This PRR revises existing Protocol language to comply with item (l) of P.U.C. SUBST. R. 25.130, Advanced Metering. PRR765 was posted on June 10, 2008. On July 17, 2008, the Protocol Revision Subcommittee (PRS) unanimously voted to recommend approval of PRR765 as submitted. On August 21, 2008, PRS unanimously voted to endorse and forward the PRS Recommendation Report and Impact Analysis to TAC. On September 4, 2008, TAC unanimously voted to recommend approval of PRR765 as recommended by PRS.

Mr. Fehrenbach questioned the naming convention in the PRR, and Mr. Dreyfus confirmed that it is consistent. **Mr. Karnei moved to approve PRR765. A.D. Patton seconded the motion. The motion passed by unanimous voice vote with no abstentions.**

PRR769 – EECP Media Appeal Change [Operations Working Group (OWG)]. Proposed effective date: November 1, 2008. No budgetary impact; no additional FTEs needed; no system changes required; existing business processes can accommodate this PRR; no impact to grid operations. This PRR removes the required energy conservation media appeal from Emergency Electric Curtailment Plan (EECP) Step 2 and allows ERCOT management to issue a media appeal for energy conservation at management's discretion, without requiring ERCOT CEO Authorization. PRR769 was posted on July 22, 2008. On August 21, 2008, PRS unanimously voted to recommend approval of PRR769 as submitted. On September 24, 2008, PRS voted to endorse and forward the PRS Recommendation Report and Impact Analysis to TAC for approval. There was one (1) abstention from the Independent Power Marketer (IPM) Market Segment. On October 2, 2008, TAC unanimously voted to recommend approval of PRR769 as recommended by TAC.

Mr. Karnei moved to approve PRR769. Mr. Kahn seconded the motion.

Mr. Fehrenbach commented that, rather than removing the media -appeal requirement entirely, it could be moved to a later stage of EECP, because there is value in educating the public about emergency grid events. Mr. Grable replied that this is a requirement to appeal for conservation, and that public education about an emergency is a different topic entirely. Chairman Smitherman noted that ERCOT could be criticized for implementing rolling blackouts unless a conservation appeal had been made. Mr. Ballard asked Mr. Saathoff when he thought it would it be beneficial to alert the media. Mr. Saathoff replied that if ERCOT is in step one of EECP and did not see itself getting out of it soon, then ERCOT should issue a public appeal. Mr. Kahn mentioned that he had no problem with later in the EECP process having a requirement to contact the media, and if for some reason ERCOT feels it is not necessary, then ERCOT could file something with the PUCT. Mr. Jenkins and Donna Nelson, PUCT Commissioner, both stated that ERCOT should be able to consider the appropriateness of an appeal in the situation, and that there are different types of emergency events: those that unfold slowly over hours, and those that happen very rapidly due to sudden changes. Chairman Armentrout suggested that the Board remand PRR769 back to TAC. Mr. Karnei withdrew his initial motion. **Andrew Dalton moved to remand PRR769 back to TAC. Charles Jenkins seconded the motion.** Before the vote, Mr. Ballard reiterated his strong preference that a media conservation appeal go out prior to rotating outages.

The motion passed by unanimous voice vote with no abstentions.

Mr. Dreyfus reported that TAC met to consider the following NPRRs:

NPRR102 – Implementation of PUC SUBST. R. 25.505(f), Publication of Resource and Load Information [Transition Plan Task Force (TPTF)]. Proposed effective date: Upon Texas Nodal Market Implementation. Incremental cost to Nodal project ($1.5M - $2M); 1/4 FTE impact to Enterprise Information Services (EIS) area; impacts to ERCOT Systems include the Energy Management System (EMS), Market Management System (MMS), Commercial Systems (COMS), EIS, and the Market Information System (MIS); ERCOT will publish Load and Resource information pursuant to the disclosure requirements in P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability of Texas Power Region, paragraph (f), adopted under P.U.C. Project No. 33490, Rulemaking Proceeding to Address Pricing Safeguards in the Markets Operated by the Electric Reliability Council of Texas; no impact to grid operations. This NPRR incorporates the disclosure requirements pursuant to paragraph (f) of P.U.C. SUBST. R. 25.505. NPRR102 was posted on February 12, 2008. On February 21, 2008, PRS unanimously voted to recommend approval of NPRR102 as revised by ERCOT comments. On March 20, 2008, PRS unanimously voted to table NPRR102 pending the development of the final Impact Analysis. On May 22, 2008, PRS unanimously voted to table NPRR102 pending development of the final Impact Analysis. On September 24, 2008, PRS voted to endorse and forward the PRS Recommendation Report as revised by TPTF comments and the Impact Analysis to TAC for approval. There was one (1) abstention from the Consumer Market Segment. On October 2, 2008, TAC unanimously voted to recommend approval of NPRR102 as recommended by PRS.

Mr. Dreyfus noted that there were changes made to NPRR102 at the Q&A session on Monday, October 20, 2008: throughout the NPRR, "48 hours" was changed to "2 days." **Mr. Fehrenbach**

moved to approve NPRR102 as modified. Mr. Kahn seconded the motion. The motion passed by unanimous voice vote with no abstentions.

NPRR113 – Load Resource Type Indicator for Ancillary Service (AS) Trades and Self-Arranged AS [ERCOT]. Proposed effective date: upon Texas Nodal Market Implementation. Incremental cost to Nodal project ($500K - $1M); no ERCOT staffing impacts; impact to ERCOT Systems including MMS, EIS, and EMS; no impacts to business functions; increases reliability of overall grid operations. This NPRR adds an indicator to Self-Arranged Ancillary Services and Ancillary Service Trades to reflect if Responsive Reserve (RRS) services are being provided from a Generation Resource, Controllable Load Resource, or non-controllable Load Resource. NPRR113 was posted on March 11, 2008. On March 20, 2008, PRS unanimously voted to refer NPRR113 to TPTF for review. On April 18, 2008, PRS unanimously voted to recommend approval of NPRR113 as revised by TPTF comments. On May 22, 2008, PRS unanimously voted to table NPRR113 until the June 19, 2008 PRS meeting pending the development of the final Impact Analysis. On September 24, 2008, PRS voted to endorse and forward the PRS Recommendation Report and Impact Analysis to TAC for approval. There was one (1) abstention from the Consumer Market Segment. On October 2, 2008, TAC unanimously voted to recommend approval of NPRR113 as recommended by PRS.

Mr. Gent moved to approve NPRR113. Mr. Kahn seconded the motion. The motion passed by unanimous voice vote with no abstentions.

NPRR124 – Resource Node Updated Definitions [ERCOT]. Proposed effective date: upon Texas Nodal Market Implementation. Incremental cost to the Nodal project ($100K-$150K); no ERCOT staffing impacts; impact to ERCOT Systems include MMS; no impacts to business functions; no impacts to grid operations and practices. This NPRR clarifies the definition of Resource Node and specifies the different Resource Node types that meet the Nodal Protocol requirements. NPRR124 was posted on April 10, 2008. On April 18, 2008, PRS unanimously voted to refer NPRR124 to the TPTF for review. On June 19, 2008, PRS unanimously voted to again refer NPRR124 to TPTF for further clarification. On July 17, 2008, PRS unanimously voted to recommend approval of NPRR124 as amended by TPTF comments and as revised by PRS. On September 24, 2008, PRS voted to endorse and forward the PRS Recommendation Report and Impact Analysis for NPRR124 to TAC for approval. There was one (1) abstention from the Consumer Market Segment. On October 2, 2008, TAC unanimously voted to recommend approval of NPRR124 as recommended by PRS.

Mr. Fehrenbach moved to approve NPRR124 as redlined based on the Q&A session discussion on Monday, October 20, 2008. Mr. Kahn seconded the motion. The motion passed by unanimous voice vote with no abstentions.

NPRR129 – Section 15, Synchronization of Zonal Protocols [ERCOT]. Proposed effective date: upon Texas Nodal Market Implementation. No incremental cost to ERCOT; no impact to ERCOT staffing; no impact to computer systems; no impact to business functions; no impact to grid operations and practices. This NPRR synchronizes zonal Protocol Section 15, Customer Registration, with the current Nodal Protocols and moves Section specific definitions and acronyms to Nodal Protocol Section 2, Definitions and Acronyms. NPRR129 was posted on May

1, 2008. On May 22, 2008, PRS unanimously voted to refer NPRR129 to TPTF for review. On August 21, 2008, PRS voted to recommend approval of NPRR129 as amended by ERCOT comments with one abstention from the Consumer Market Segment. On September 24, 2008, PRS unanimously voted to endorse and forward the PRS Recommendation Report and Impact Analysis for NPRR129 to TAC for approval. On October 2, 2008, TAC unanimously voted to recommend approval of NPRR129 as recommended by PRS.

Mr. Fehrenbach requested that any inconsistencies be part of the black-line language. **Mr. Fehrenbach moved to approve NPRR129 and requested that TAC review the two sections to ensure they are consistent and that they are consistent with current practices. Mr. Kahn seconded the motion. The motion passed by unanimous voice vote with no abstentions.**

NPRR144 – Five RUC Deployments Needed Before Requiring Verifiable Costs [Verifiable Costs Working Group (VCWG)]. Proposed effective date: upon Texas Nodal Market Implementation. No incremental cost to ERCOT; no impact to ERCOT staffing; no impact to computer systems; no impact to business functions; no impact to grid operations and practices. This NPRR will increase the time Qualified Scheduling Entities (QSEs) and Resources have to prepare verifiable cost submissions for units that are unlikely to be struck in the Reliability Unit Commitment (RUC) process. NPRR144 was posted on July 25, 2008. On August 21, 2008, PRS voted to recommend approval of NPRR144 as amended by TPTF comments with one (1) abstention from the Consumer Market Segment. On September 24, 2008, PRS unanimously voted to endorse and forward the PRS Recommendation Report and Impact Analysis for NPRR144 to TAC for approval. On October 2, 2008, TAC unanimously voted to recommend approval of NPRR144 as recommended by PRS.

Mr. Fehrenbach pointed out that this issue has been an on going debate in various committees. **Mr. Fehrenbach moved that the Board reject NPRR144.** There was no second to this motion.

Mark Walker pointed out that generic costs will be much more limited under Nodal than in the zonal market, and that it will be very difficult for Market Participants to prove Verifiable Costs. Mr. Ballard asked how many more RUCs are anticipated and why was five picked as the limit. Mr. Dreyfus responded that he was not sure how many RUCs will be generated and that five was chosen because it is more than one and less than ten. **Mr. Walker moved to approve NPRR144. Mr. Wilkerson seconded the motion. Mr. Dalton proposed a friendly amendment to change the limit from 5 to 3, which was not accepted by the moving or seconding Directors. The motion passed by voice vote with two opposition votes (Messrs. Fehrenbach and Dalton).**

Mr. Dreyfus referred back to the TAC Report presentation and asked the Board to consider the MCPE Cap and Shadow Price Methodology. **Mr. Gent moved to approve the MCPE Cap and Shadow Price Methodology. The motion was seconded by Mr. Wilkerson. The motion passed by unanimous voice vote with no abstentions.**

At this time, John Dumas gave a presentation on Ancillary Services Methodology. Mr. Gent reported that not everyone may not be aware of how much consideration the Board gave to the low CPS2 scores. He further reported that this appears to not encourage wind generators to meet their schedules. Mr. Dumas advised that what ERCOT is focusing on now is more how the wind units are performing, that it is still in a discussion phase and that they are actively developing accurate metrics.

Mr. Ballard reported that WMS has taken up cost allocation and that ROS has taken up better optimization. He further reported that he does not feel the methodology is fully developed and that it still does not have wind metrics. He advised that at this time he did not feel he could support the proposal.

Dr. Patton advised that he was concerned that the study may have been done inappropriately on a set basis and with disregard for transmission constraints. Mr. Dumas agreed that the study did not account for transmission. He further noted that the study only monitored one hour and that it was not representative of a whole day or whole year, but ERCOT wanted to get an idea of the effect of the resources.

Mr. Fehrenbach pointed out that the study is adjusting non-spin for the preceding 90 days and with wind being a seasonal product, he would assume that the forecasts are more predictable in June and in April. He commented that the prior 90 days were not necessarily indicative of the current month. Mr. Dumas replied that the study is not perfect, but it is an approach that links reserves and forecasts. Mr. Fehrenbach replied that he did not feel there was a clear need for this at this time.

Mr. Jenkins pointed out that most would recognize that with wind, adjustments need to be made and that all would agree that we don't know the final answer and there is further work to do, but he felt this was a step in the right direction.

Mr. Dalton asked why load is being penalized and why net load is not being calculated on wind generators so that they could be charged directly. Mr. Saathoff agreed that there is room to optimize this. But he advised that he felt strongly that changes need to be made now since we are going into a peak wind season and that ERCOT is open and willing to work with Market Participant groups to optimize this.

Chairman Armentrout asked if the costs are verifiable. Mr. Saathoff replied that we know what the prices will be, but it is harder to determine what the prices would have been.

Mr. Karnei mentioned that the Board's concerns are valid, but he believes this is incremental and necessary. **Mr. Karnei moved to approve the Ancillary Services Methodology.**

Dr. Patton asked for clarification regarding the additional costs and wanted to know if the costs are uplifted to everyone. Mr. Dumas replied that they are uplifted to load.

Mr. Dalton inquired if the Ancillary Services Methodology would be rolling out November 1, 2008. Mr. Dumas replied affirmatively. Mr. Dalton asked why there was such a push to approve this now rather than bundling this with the payment-allocation issue and approving it all at a later date. Mr. Dumas replied that there had been many discussions in the Wind Operations Task Force regarding increasing output from 5500 to 8500 megawatts by the end of the year. He advised that ERCOT was trying to move quickly to keep up and that he thought this was the right first step. He mentioned that ERCOT will continue to work with stake holders and will review any new proposals that come in.

Mr. Gent seconded the motion made by Mr. Karnei. Chairman Armentrout suggested adding a friendly amendment requesting that ERCOT staff report back to the Board on costs related to Ancillary Services Methodology in six months. Mr. Dalton suggested a further amendment requesting that ERCOT staff report back on financial impacts in January 2009 and that he would like to have a recommendation from TAC on how ERCOT is going to deal with the expenses after a full quarter. Chairman Armentrout suggested that ERCOT staff provide a monthly report on the Ancillary Services Methodology and that the Board could discuss the issue at length at the Board Strategic Planning Event in February 2009. **Mr. Dalton revised his friendly amendment to have monthly updates and a fuller report three months from the November start date. The friendly amendment was accepted. As amended, the motion passed by voice vote with two opposed (Messrs. Fehrenbach and Ballard) and one abstention (Dr. Patton).**

Mr. Dreyfus concluded his presentation with a discussion of "Study Horsepower," expressing Market Participant concerns that ERCOT, and the market generally, may not have resources available to perform all required analyses. Mr. Doggett agreed with the concerns, and noted that staff resources are limited but that he is also trying to identify broad industry expertise that can assist. Mr. Saathoff noted that demands on ERCOT only increased over time, and that he was focusing on a reorganization of System Planning, working with Human Resources for more money, and looking for outside help as well. Clayton Greer, J Aron, noted that the market views this as a budgetary issue, and is asking the Board to allocate more resources to study and analysis. Mr. Patton stated his belief that far more study of wind is needed, and that resources in Operations generally and Compliance specifically need to be beefed up.

The last TAC item discussed by the Board was consideration of 2009 Commercial Significant Constraints (CSCs), including appeals of alternative CSC proposals. Presentations were provided by Mr. Dreyfus, Richard Ross of AEP as appellant in favor of option 3h, Barbara Clemenhagen of Topaz as the TAC Advocate for option 3i, and David Bell, General Manager of West Central Texas Municipal Water District, in favor of option 3b.

Mr. Dalton asked why Option 3b was voted down at WMS. Mr. Dreyfus responded that the consensus based on ERCOT's analysis was that there is a better likelihood of lower cost and better reliability with the other options.

A.D. Patton asked Mr. Ross to clarify the suggestion is that Option 3i will move the Oklaunion station to the west if it is currently in the west. Mr. Ross replied that it is in the 2008 west zone, which would be different than the 2009 west zone.

Mr. Dalton asked how many times the Oklanion-Bowman line was out. Beth Garza replied that she did not know precisely, but she believed that the outage percentage was in the single digits.

Chairman Smitherman asked Mr. Dreyfus to confirm that the voting on Option 3h was two in favor, twenty-three opposed and five abstentions, which Mr. Dreyfus did.

Chairman Armentrout pointed out that TAC members routinely advocate for their own companies and/or segments, but some phraseology in one of the appeal presentations was over and above an advocacy process, including a purported claim of discrimination. He asked if there was anything else that needed to be shared regarding issues that were not allowed to be brought up. Mr. Kahn explained that Ms. Garza and ERCOT Legal were prepared to discuss this claim and to advise that the Protocols had been followed. Ms. Garza responded that she and ERCOT Legal are prepared to go line by line and prove that there was no discrimination against any company or segment and that everyone had had sufficient notice of ERCOT staff's position and an opportunity to respond. Chairman Smitherman asked Mr. Grable if he felt that all legal requirements had been met. Mr. Grable replied affirmatively.

Mr. Karnei moved to approve Option 3i as recommended. Mr. Wilkerson seconded the motion. The motion passed by voice vote with one opposed (Mr. Fehrenbach) and one abstention (Mr. Dalton).

Reschedule of November 2008 Board Meeting Date (Agenda Item No. 12)

Mr. Grable advised the Board that the November 2008 Board Meeting needed to be rescheduled to Monday, November 17, rather than Tuesday, November 18, due to a legislative meeting. He noted that the reschedule of the November 2008 Board Meeting was added to the Agenda so that it could be publicly noted. Mr. Espinosa requested that ERCOT provide the Board with a revised schedule of all Board-related meetings.

Other Business (Agenda Item No. 13)

Chairman Armentrout asked the Board if they had any other non-voting business to discuss. The Board had no additional business.

Future Agenda Items (Agenda Item No. 14)

Chairman Armentrout asked the Board if they had any items to add to Future Agenda Items. The Board had no additional items.

Executive Session (Agenda Item Nos. 15, 15.a.-15.e.)

Chairman Armentrout adjourned the meeting to Executive Session at approximately 3:45 p.m.

Executive Session Voting Matters (Agenda Item No. 16)

Chairman Armentrout reconvened the open session at approximately 5:22 p.m.

Mr. Ballard moved to approve a contract item related to Independent Market Monitor (IMM) services under Agenda Item 15e. Mr. Dalton seconded the motion. The motion passed by unanimous voice vote with no abstentions.

Mr. Wilkerson moved to approve two contract items related to vendor not-to-exceed limitations under Agenda Item 15e. Mr. Gent seconded the motion. The motion passed by voice vote with one opposed (Mr. Fehrenbach) and no abstentions.

Mr. Helton moved to approve a contract item related to the hiring of a new vendor under Agenda Item 15e. Ms. Zlotnik seconded the motion. The motion passed by unanimous voice vote with no abstentions.

Mr. Kahn moved to approve Resolution 1 for Agenda Item 15d. Mr. Cox seconded the motion. The motion passed by voice vote with two opposed (Messrs. Ballard and Dalton) and no abstentions.

Mr. Kahn moved to approve Resolution 2 for Agenda Item 15d. Mr. Gent seconded the motion. The motion passed by unanimous voice vote with no abstentions.

Mr. Wilkerson moved to approve Resolution 3 for Agenda Item 15d. Mr. Kahn seconded the motion. The motion passed by voice vote with two opposed (Messrs. Ballard and Dalton) and no abstentions.

Chairman Armentrout moved to approve a regulatory litigation filing under Agenda Item 15b. Mr. Gent seconded the motion. The motion passed by voice vote with one abstention (Mr. Ballard).

Adjournment

Chairman Armentrout adjourned the meeting at approximately 5:30 p.m.

EXHIBIT 2

ERCOT Protocols
Section 7: Congestion Management

October 1, 2008

7 CONGESTION MANAGEMENT

7.1 Overview of ERCOT Congestion Management

ERCOT employs a Zonal Congestion management scheme that is flow-based, whereby the ERCOT Transmission Grid, including attached Generation Resources and Load, will be divided into a predetermined number of Congestion Zones. Each Congestion Zone is defined such that each Generation Resource or Load within the Congestion Zone boundaries has a similar effect on the loading (Shift Factor) of Transmission Facilities between Congestion Zones. For purposes of solving Zonal Congestion the Shift Factor will be assumed the same for: (i) all Generation Resources deemed likely to vary their output and (ii) Loads within a Congestion Zone. Therefore any imbalance between Loads and Generation Resources in a Congestion Zone will be deemed to have the same impact on a given loading between Congestion Zones.

This Congestion management scheme applies zonal Shift Factors, determined by ERCOT, to predict potential Congestion on Commericially Significant Constraints (CSCs) under the known topology of the ERCOT System. The zonal Shift Factors determined by ERCOT should most closely represent the effect of Generation Resources deemed likely to vary their output and Loads in the Congestion Zone on the CSCs with the current topology of ERCOT System. This scheme is used in the Day Ahead and Adjustment Periods to evaluate potential Congestion and notify Market Participants accordingly. ERCOT also uses this scheme, along with other factors, to determine if it should procure Replacement Reserve Service in a Congestion Zone to provide additional Balancing Energy Service to solve expected Congestion. ERCOT will use monthly zonal Shift Factors to post and analyze the Schedule impact on CSCs until it implements calculations of interval Shift Factors in the system.

ERCOT will manage transmission Congestion and categorize the cost of Congestion management as either Zonal Congestion management costs or Local Congestion management Costs. Zonal Congestion management costs are those costs attributable to managing Congestion on CSCs or predefined Closely Related Elements (CRE). The costs of managing Zonal Congestion will be directly assigned to Qualified Scheduling Entities (QSEs) based on the impact of each QSE's portfolio on CSCs. All other Congestion management costs are considered Local Congestion management costs.

ERCOT will use the Zonal Congestion management model with Shift Factors of Generation Resources and Loads on CSCs and zonal Balancing Energy Service Market Clearing Price for Energy (MCPE) to determine the Shadow Prices of energy across corresponding CSCs. In addition, ERCOT will directly assign to QSEs the costs of any Replacement Reserve Service (RPRS) procured on a zonal basis for Congestion management purposes. ERCOT will use these Shadow Prices in settlement to directly assign to QSEs the cost of managing Zonal Congestion to QSEs.

ERCOT will set the Shadow Price cap at a level that ERCOT calculates to be in alignment with the prevailing system-wide offer cap defined in paragraph (g)(6) of PUCT SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, and Section 6.11, System-Wide Offer Caps. In some cases, such as where two (2) or more CSCs are simultaneously binding, MCPEs may be generated that are at levels higher than the prevailing system-wide offer cap or lower than the Balancing Energy offer floor. When that occurs, ERCOT shall make Real Time or ex-post adjustments to zonal MCPEs to ensure that MCPEs do not exceed the system-wide offer cap or fall below the Balancing Energy offer floor, and adjust CSC Shadow Prices accordingly. ERCOT shall describe the ERCOT Board-approved process for making price adjustments in a Market Operations Bulletin that will be posted on the Market Information System (MIS) Public Area. ERCOT shall send a Notification to Market Participants informing them of any change to the Shadow Price cap at least ten (10) days prior to implementation of the new system-wide offer cap.

The Local Congestion management scheme relies on a more detailed Operational Model to determine how each particular Resource or Load impacts the transmission system. This model does not use portfolios and uses the current known topology of the transmission system.

ERCOT will Uplift the cost to solve Local Congestion pro rata to each QSE based on its Load Ratio Share.

ERCOT will manage Congestion by:

(1) Evaluating the levels of Zonal Congestion and any other Congestion during the Day Ahead, the Adjustment Period and the Operating Period using appropriate models of the ERCOT Transmission Grid;

(2) Examining the impacts of QSE energy schedules on CSCs;

(3) Posting on the MIS, the total megawatt quantity impacts on every CSC, and allowing QSEs to adjust schedules to mitigate potential Congestion on the CSCs;

(4) Procuring during the Adjustment Period, as needed, RPRS to use with other Resources for which QSEs have submitted Balancing Energy bids to provide sufficient capacity for Balancing Energy flows in the Operating Hour while respecting operational limits of the ERCOT Transmission Grid;

(5) Determining settlement for QSEs providing RPRS procured to manage Congestion; and

(6) Determining settlement for QSEs providing Balancing Energy associated with resolving Zonal Congestion.

ERCOT will carry out these steps in accordance with this Section and the scheduling and Ancillary Service scheduling and selection requirements in Section 4, Scheduling, and Section 6, Ancillary Services, respectively.

7.2 CSC Zone Determination Process

By November 1 of each year, the appropriate ERCOT subcommittee will report to the TAC and ERCOT Board with recommended CSC designations, resulting Congestion Zone boundaries with any granted exemptions noted, CRE designations and associated Boundary Generation

Resources for ERCOT Board review and approval. Shortly after ERCOT Board approval, CSCs and resulting Congestion Zone boundaries and CRE designations will be posted on the MIS. This posting will include a station and bus-by-bus identification of each Congestion Zone.

7.2.1 Process for Determining CSCs

CSCs and resulting Congestion Zones will be reassessed annually by November 1 of each year. ERCOT staff will use the following process to identify CSC's:

(1) By August 1, of each year, ERCOT staff will complete an analysis of Load flow data using the latest Steady State Working Group Data Set A summer peak case and will determine expected operating limits, candidate CSCs and associated constraints to be used in the designation of CSCs for the upcoming calendar year using the following steps:

(a) Determination of new CSC candidates:

(i) Candidate CSCs may be determined using transfer analysis between Study Zones. Study Zones are groupings of buses used to test transfer limits using power system simulation tools. These Study Zones can be either of the following: (1) reasonable approximations of the final Congestion Zones; Weather Zones, SSWG Areas or Zones; or (2) any grouping of buses by geographic region or generation/Load pocket. Candidate CSCs will often be the contingency that repeatedly causes multiple limiting elements to reach 100% of their emergency rating at high transfer levels. If a transmission line is repeatedly the limiting element under multiple contingencies it will be considered a CSC candidate.

(ii) Candidate CSCs may also be identified through an evaluation of the actual annual Congestion costs from the prior year. For this purpose, Congestion costs include the cost of any zonal Balancing Energy Service, RMR Service, OOMC Service, Replacement Reserve Service, OOME Service, or Resource-specific Dispatch Instructions used to resolve Congestion on that particular transmission path in that particular direction during the prior year. Candidate CSCs may also be identified by considering projected annual Congestion costs for the CSC designation year. Since this type of data reflects past system topology and generation, generation and transmission system changes expected to be in service in the CSC designation year shall also be considered.

(iii) Candidate CSCs may also be identified based on ERCOT's operational experience.

(b) If no new candidate CSCs are considered other than the immediately preceding year's CSCs, then ERCOT staff shall use the Congestion Zones from the immediately preceding year as Study Zones.

(c) If new candidate CSCs are considered, then ERCOT staff shall calculate Shift Factors and perform cluster analysis based on the candidate CSCs to create Study Zones.

(d) ERCOT staff shall perform system simulation studies with transfers between the Study Zones and find constraints on the transmission system to determine if candidate CSCs are appropriate for designation as CSCs.

(e) ERCOT staff shall recommend whether the candidate CSCs qualify for CSC designation based, in part, on the criterion that there must be a sufficiently competitive market to resolve Congestion on the transmission path to be considered for CSC designation. One factor that will be considered when assessing whether a sufficiently competitive market exists is the concentration of capacity ownership or control by Market Participants or their Affiliates, compared to the distribution of shift factor impacts.

(2) CSC approval process: The appropriate ERCOT Technical Advisory Committee (TAC) Subcommittee will review the results and the process followed above to determine the list of constraints to be recommended for approval to the TAC and the Board.

7.2.2 Congestion Zone & Zonal Shift Factor Determination Methodology

ERCOT staff will take the following steps to determine Congestion Zones and Zonal Shift Factors:

(1) Shift Factors are developed using a linearized (DC) model to identify the impact of each transmission bus on each CSC relative to an ERCOT reference bus.

(2) A statistical clustering analysis will be used to aggregate transmission buses into zones based upon similar Shift Factors relative to all CSCs. The clustering must meet the following criteria: (i) each CSC must straddle a zonal boundary (however, not every zonal boundary need be straddled by a CSC); and (ii) station IDs as provided by TDSPs in Protocol Section 15.1.2.5, Response from TDSP to Registration Notification Request, can be assigned only into one Congestion Zone.

The following measurements will be calculated for each combination of zones: (i) the maximum difference between the Zonal Shift Factor and the Shift Factor of any generation bus within the zone; and (ii), the R^2 (coefficient of determination) from the cluster analysis.

(3) If the clustering process described in (2), above, results in the splitting of two or more buses within any single station into different zones, then the following process will be used to adjust the zone selection to place all buses within a single station in the same zone:

(a) For Generation Resource stations, determine which zone contains the largest amount of generating capacity of the station and assign all buses of that station to that zone;

(b) For all other stations, determine which zone is assigned the largest total amount of Customer Load of the buses in the station and assign all buses of that station to that zone;

(c) If there is no Load or generation in the station, or if the amount of generation and/or Load assigned to individual station buses are equal, then the Load or generation shall be assigned to the zone containing the lowest bus number of the station.

(4) Zonal Shift Factors for each CSC will be determined by averaging the individual bus Shift Factors within each Congestion Zone for the corresponding CSC, weighted by the megawatt levels on the bus in the Load flow base case used to determine CSC Limits from Generation Resources deemed likely to vary their output.

The appropriate ERCOT Technical Advisory Committee (TAC) Subcommittee will review the results and the process followed above to determine the Congestion Zones to be recommended for approval to the TAC and the Board.

(5) Thirty (30) days prior to TAC review, a NOIE may request an exemption to its zonal placement by submitting a request to ERCOT for consideration. ERCOT staff will evaluate the merits of the request and authorize the exemption based on the following criteria:

(a) Exemptions shall not cause significant operational impact to the ERCOT System. This will normally be satisfied if the request will not result in a change in the annual average Shift Factor for the original or requested Congestion Zone by more than five percent (5%). After the proposed move, the Zonal Shift Factor in each of the original and requested Congestion Zones shall be no less than ninety-five percent (95%), and no more than one hundred and five percent (105%), of its original Zonal Shift Factor before the proposed move.

Because only buses with generation have an impact on the calculation of Zonal Shift Factors, if no generation exists at a bus that is part of an exemption request, a token generator of one (1) MW will be placed at that bus to test the impact of moving that bus from one (1) zone to another. This will be done to all buses that make up a request for exemption. For example, if an Entity is requesting an exemption for five (5) buses and only one (1) bus has generation On-line in the Load flow case used to test the impact, one (1) MW of generation will be placed at the four (4) other buses and the impact of all five (5) buses on Zonal Shift Factors will be determined as a group as opposed to individually. The Load flow case used to determine this impact will be the same Load flow case used to calculate annual TCR quantities.

(b) Exemptions shall not have a commercial impact/gain for the requestor. This will be measured by whether or not the scheduling which would otherwise result would be eligible for Pre-assigned Congestion Rights.

7.2.3 Determining Closely Related Elements (CREs)

For each year, ERCOT staff shall identify potential CREs using, at a minimum, the following process:

(1) Determine the Zonal Average Shift Factor for a particular CSC (Xz) for each Zone (z).

(2) Determine the zonal average Shift Factor for the candidate CRE (Yz) for each Zone z using the same generation weighting as in (1) but ignoring Boundary Generation Resource buses that would cluster into a different Congestion Zone with respect to the CRE.

(3) Determine positive "a" applying least-square curve fitting to the following equation:

$\mathbf{Y_z = a\,(X_z) + b_z}$ **for all Zones z.**

(4) Using "a" from (3), determine the maximum absolute value of bz.

(5) Also determine the total capacity (MW) of Boundary Generation Resources that would cluster into a different Congestion Zone.

(6) If the maximum absolute value of b_z is less than a threshold set by the appropriate TAC subcommittee, not to exceed 0.2, and the total capacity of Boundary Generation Resources that would cluster into a different Congestion Zone is less than 1,500 MW, then the element is a CRE for the particular CSC.

ERCOT staff may identify potential CREs in addition to the potential CREs identified through the process described above as they determine appropriate. As part of the CRE identification process, ERCOT staff shall evaluate each contingency element/limiting element pair combination to determine if deployment of zonal balancing will be effective for managing the post-contingency flow on the limiting element. Based on this evaluation, ERCOT shall develop its proposed CREs and list of contingencies for managing CSC and CRE related Congestion. ERCOT shall present all proposed CREs and list of contingencies for managing CSC and CRE related Congestion, including justification for their inclusion, to the appropriate ERCOT TAC Subcommittee for approval.

During the effective year, ERCOT staff may propose modifications to the list of CREs or the approved list of contingencies for managing CSC and CRE related congestion, including the expected duration of those modifications, as needed to more closely represent actual system constraints that can be effectively resolved by Zonal Balancing Energy deployments. Any modifications to the list of CREs or the approved list of contingencies for managing CSC and CRE related congestion will not affect Congestion Zone definition or composition, nor will they affect CSC definitions. ERCOT shall present modifications proposed to the list of CREs or the approved list of contingencies for managing CSC and CRE related congestion after the start of the year to TAC for approval. TAC will have seven (7) days to take action on the proposed modification. If TAC takes no action within seven (7) days, the proposed modification shall be deemed approved.

7.2.4 Determining Generation Resources Deemed Likely to Vary Their Output

At the beginning of each year, ERCOT will compile a list of all Generation Resources fueled by nuclear fuel, coal or lignite. ERCOT will exclude such units from the calculation of Zonal Shift Factors for the rest of the year. All other Generation Resources will be deemed likely to vary their output.

7.3 Congestion Management for CSCs/Zonal Congestion

7.3.1 Determination of Zonal Congestion

ERCOT will analyze energy schedules to determine the existence and extent of Zonal Congestion as part of the Day Ahead Scheduling Process.

7.3.2 Resolution of Zonal Congestion

ERCOT will resolve Zonal Congestion by the following means:

(1) Using adjusted Balanced Schedules received from QSEs after ERCOT's posting of CSC impacts greater than the CSC Limit, ERCOT will reassess the resulting level of Zonal Congestion. ERCOT will take no further Zonal Congestion actions if the adjusted Balanced Schedules resolve initial Zonal Congestion.

(2) If Zonal Congestion still exists following receipt of adjusted Balanced Schedules, ERCOT may procure RPRS in accordance with Section 6.6.3.2, ERCOT Ancillary Services Procurement during Adjustment Period, provided that sufficient Resources are available to provide Balancing Energy in the Operating Period, in accordance with Section 6.6.3.2. ERCOT will then balance the energy within the ERCOT System in the Operating Period respecting all operational limitations of the ERCOT System.

(3) Zonal Balancing Energy can be deployed only for Congestion Management purposes to resolve flow limit violations on CSCs and CREs where the base case or post-contingency limiting element is the CSC or CRE, unless an Emergency Condition is declared by ERCOT. ERCOT must manage CSC and CRE related Congestion using the approved list of contingencies for managing CSC and CRE related Congestion.

(4) Congestion is resolved in Real Time as follows:

(a) Using Zonal Shift Factors, estimate zonal BES deployments needed to maintain flows within CSC Limits. If the Congestion that needs to be resolved is on a

CRE, then Boundary Generation Resources unique to that CRE will be instructed to operate at the respective Resource Plan levels (i.e., this is not an instructed deviation from schedule or Resource Plan).

(b) Based on (a), deploy unit specific instructions to manage Local Congestion. The Resource specific instructions will be defined as instructed deviations using the following criteria:

(i) When a Resource is instructed to operate at or above an instructed output level and the Resource Plan output level is below the instructed output level, the instructed deviation will be defined as the difference between the instructed output level and Resource Plan output level for the target interval.

(ii) When a Resource is instructed to operate at or below an instructed output level and Resource Plan output level is above the instructed output level, the instructed deviation will be defined as the difference between the instructed output level and Resource Plan output level for the target interval.

(iii) When a Resource is requested to go to an instructed output level, the instructed deviation will be defined as the difference between the instructed output level and the Resource Plan output level.

(iv) Otherwise, the Resource specific deployment will not be defined as instructed deviation.

(c) Clear the Balancing Energy Service market to maintain system power balance and the CSC flow within the CSC Limit.

(d) In the event of a contingency, estimate BES deployment to maintain flows within pre-second contingency CSC Limits and deploy unit-specific instructions to manage any resulting Local Congestion and clear the BES market to maintain CSC flows within pre-second contingency CSC Limits.

(5) The Shift Factors for CSCs and CREs shall be at the same value.

The result of Congestion Management should ensure that:

(1) Balancing Energy MCPEs are the same in all zones if no CSC or CRE is constrained.

(2) Balancing Energy MCPEs will be different in two or more Congestion Zones only if one or more CSCs/CREs are constrained.

(3) The Shadow Price of a constrained CSC will be calculated by taking the difference in Balancing Energy MCPEs between any two zones divided by the difference in Zonal Shift Factors on the corresponding CSC of the two zones even in the event of an Outage of the CSC. If there is no feasible solution, then these criteria may not be met.

7.3.3 [Expired 2/15/2002]

7.3.3.1 [Expired 2/15/2002]

7.3.3.2 [Expired 2/15/2002]

7.3.3.3 [Expired 2/15/2002]

7.3.3.3.1 [Expired 2/15/2002]

7.3.4 Settlement of Zonal Congestion

7.3.4.1 Balancing Energy CSC Congestion Charge

The calculation for Zonal Congestion Management Charge is as follows:

$$I_{CSCiq} = \Sigma\, ((QSS_{iqz} - SO_{iqz}) * SF_{zcsc})_z$$

If $I_{CSCiq} > 0$ then,

$$CSC_{BECSCiq} = SP_{CSCi} * MAX\,(0, I_{CSCiq})$$

Else (counterflow)

$$CSC_{BECSCiq} = SP_{CSCi} * I_{CSCiq}$$

End

$$CSC_{BEiq} = SUM\,(CSC_{BECSCiq})_{CSC}$$

i	Interval being calculated
q	QSE
z	Congestion Zone
CSC	Commercially Significant Constraint
$CSC_{BECSCiq}$	CSC Energy Related Congestion Charge, per interval, per CSC, per QSE
CSC_{BEiq}	CSC Energy Related Congestion Charge, per interval of that QSE
SP_{CSCi}	Shadow Price per CSC, per interval
I_{CSCiq}	Scheduled MW Impact per CSC, per interval, per QSE
SF_{zcsc}	Commercial Model Shift Factor of Generation Resources deemed likely to vary their output per CSC, per zone
QSS_{iqz}	QSE Supply Schedule per interval, per zone, per QSE
SO_{iqz}	Scheduled Obligation (prior to Real Time) per interval, per zone, per QSE

ERCOT will compute the Zonal Shift Factors for settlement purposes using Shift Factors of Generation Resources within the zone deemed likely to vary their output, weighted by the generation level in the monthly base case. The monthly base case will be the most recent base case used by ERCOT but no less current than the base case used by ERCOT to determine the number of TCRs available for sale for the corresponding month.

7.3.4.2 Replacement Reserve Service Zonal Congestion Charge

Replacement Reserve Zonal Congestion costs will be allocated directly to the QSE impacting the CSC. The Replacement Reserve Zonal Congestion costs per interval per QSE will be determined by multiplying the Shadow Price of CSC capacity by the QSE's CSC impact and in that interval.

The CSC impact is determined by taking for each Congestion Zone, the maximum difference, in any of the four intervals in an hour, between each QSE's Supply schedules and the QSE Obligation schedules at the time of each round of Replacement Reserve capacity procurement multiplied by the Zonal Shift Factor. The calculation of the Replacement Reserve Service Zonal Congestion Charge will be as follows:

$$\mathbf{CSC_{RPhq} = SPC_{CSCh} * MAX\ (0, I_{CSChq}))}$$

$$\mathbf{I_{CSChq} = MAX\left[0, MAX\left[\Sigma\ ((QSS_{TOPiqz} - QOS_{TOPiqz}) * SF_{zcsc})_z\right]_n\right]}$$

Where:

h	hour being calculated
i	interval within hour h
n	The number of times that RPRS is procured.
q	QSE
z	Congestion Zone
CSC	Commercially Significant Constraint
CSC_{RPiq}	CSC Replacement Reserve related Congestion charge, per interval, per QSE
SPC_{CSCi}	Capacity Shadow Price per CSC, per interval
I_{CSCiq}	Scheduled MW Impact per CSC, per interval, at the time of purchase, per QSE
SF_{zcsc}	Zonal Shift Factor per CSC, per zone
QSS_{TOPiqz}	QSE Supply Schedule per interval, per zone, at the time of purchase, per QSE
QOS_{TOPiqz}	QSE Obligation Schedule per interval, per zone, at the time of purchase, per QSE

7.4 Congestion Management for Local Congestion

7.4.1 Determination of Local Congestion

ERCOT will use the Operational Model of the ERCOT System in combination with QSE energy schedules and ERCOT forecasted Load to determine the extent of Local Congestion.

When ERCOT identifies Local Congestion on a repeated basis ERCOT shall have procedures established to contact the appropriate TDSP to:

(1) Verify that ratings of Transmission Facilities in the ERCOT Operational Model causing the event are current and correctly represented;

(2) Verify, when the TDSP's analysis results differ from those of ERCOT, that the configuration of the transmission system in the ERCOT Operational Model matches that in use by the TDSP. To recognize operational time constraints, such verification will focus on transmission elements believed to have impacted the event; and

(3) Mutually identify with the TDSP any additional operational intervention or system monitoring that could be implemented to manage recurring Congestion due to a recurring cause.

If it is determined that rating(s) in the ERCOT Operational Model or configuration of the Transmission Facilities are not correct, then the TDSP will provide, via submittal of a Service Request on the ERCOT MIS, written confirmation of the correction. Once written confirmation is completed, ratings in the ERCOT Operational Model will be updated in the Real Time systems by the close of the next Business Day, and such rating changes and any needed configuration changes will be included in the next scheduled Operational Model database update. Once additional operational intervention to the transmission system has been identified (if any) to relieve Congestion and mutually accepted by both ERCOT and TDSP operators, the necessary operational instructions shall be prepared and implemented as soon as practicable.

ERCOT will use an interim practice between the identification of a problem and the final authorized submittal of a Service Request in order to implement corrections as soon as practicable. The interim practice will allow an authorized or alternate contact to provide corrected ratings to ERCOT by email. ERCOT will enter that rating into the Real Time systems to be used in current operating activities on a temporary basis. After the Service Request documentation is received by ERCOT, permanent changes will be made in the Operational Model and loaded into the operating systems.

7.4.2 Resolution of Local Congestion

ERCOT will procure RPRS if necessary to provide sufficient capacity to resolve forecasted Local Congestion. ERCOT will purchase RPRS from the Resource(s) having the lowest cost per megawatt based on each Resource's Resource Category Generic Cost and its ability to resolve the Congestion given its Shift Factor on the Local Congestion.

ERCOT will instruct and Dispatch Resources in Real Time in a manner that does not exceed the units' operational limits known to ERCOT. The Resources that have been instructed to operate within a range to resolve Local Congestion are paid or pay a price, in accordance with Section 7.4.3.1, Balancing Energy Up from a Specific Resource, Section 7.4.3.2, Balancing Energy Down from a Specific Resource, and Section 6.8, Compensation for Services Provided.

The Local Congestion Costs are embedded in each service deployed to resolve Local Congestion such as OOMC, OOME, and unit specific premiums.

The formula to calculate Local Congestion Replacement Reserve payment can be found in Section 6.8.1.11, Local Congestion Replacement Reserve Payment to QSE, of these Protocols.

7.4.3 Settlement of Local Congestion Costs

Net Local Congestion costs will be settled in the Balancing Energy settlement process.

7.4.3.1 Balancing Energy Up from a Specific Resource

(1) In accordance with Section 6.7.1.2, Deployment of Balancing Energy when Congestion Occurs, whenever a specific Resource with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Up, is deployed incrementally to solve Local Congestion, the QSE will be paid the difference between the MCPE of the Congestion Zone in which the specific Resource is located and the incremental bid premium specified. Aggregated Unit rules as described in Section 6.8.2, Capacity and Energy Payments for Out of Merit Service, apply to Aggregated Units approved by ERCOT.

The calculation of the payment for Balancing Energy Up from a specific Resource is as follows:

$$\mathbf{LPC_{RSUquiz} = -1 * \Sigma\, ((PM_{qiuz} - MCPE_{iz})* Max\,(0, Min\,(MR_{qiuz} - OL_{qiuz}, IOL_{qiuz} - OL_{qiuz})))}$$

$$\mathbf{LPC_{RSUqviz} = -1 * \Sigma\, ((PM_{qivz} - MCPE_{iz})* Max\,(0, Min\,(MR_{qivz} - OL_{qivz}, NETUEQ_{ivq})) * LBEAGR_{ivq})}$$

For gas-fired units:

$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$

$PM_{qiuz} = Max\,(FBPM_{qiuz}, MCPE_{iz})$

$PM_{qivz} = Min(PM_{qiuz})$

For all other Resource categories:

$PM_{qiuz} = Max\,(BPM_{qiuz}, MCPE_{iz})$

$PM_{qivz} = Min(PM_{qiuz})$

$NETUEQ_{ivq}$	=	Max [0, (($NETOOMUEQ_{ivq}$ + $NETLBEUQ_{ivq}$) – ($NETOOMDEQ_{ivq}$ + $NETLBEDQ_{ivq}$))]
$NETOOMUEQ_{ivq}$	=	Max(0, (SUM($I_{OOMUPqui}$)$_u$ – SUM($I_{OOMDNqui}$)$_u$))
$NETLBEUQ_{ivq}$	=	Max (0, (SUM($LBEUQ_{qui}$)$_u$ – SUM($LBEDQ_{qui}$)$_u$))
$NETOOMDEQ_{ivq}$	=	Max(0, (SUM($I_{OOMDNqui}$)$_u$ – SUM($I_{OOMUPqui}$)$_u$))
$NETLBEDQ_{ivq}$	=	Max(0, (SUM($LBEDQ_{qui}$)$_u$ – SUM($LBEUQ_{qui}$)$_u$))
$LBEAGR_{ivq}$	=	[(SUM($LBEUQ_{qui}$)$_u$ + SUM($LBEDQ_{qui}$)$_u$)] / [SUM($LBEUQ_{qui}$)$_u$ + SUM($LBEDQ_{qui}$)$_u$ + SUM($I_{OOMUPqui}$)$_u$ + SUM($I_{OOMDNqui}$)$_u$]

Where:

d	Operating Day of interval i
i	interval
q	QSE
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
BPM_{qiuz}	Incremental bid premium for that specific unit per interval
$FBPM_{qiuz}$	Incremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The Instructed output level for the unit given the unit-specific instruction
$I_{OOMDNqui}$	OOM Energy Down Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$I_{OOMUPqui}$	OOM Energy Up Instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$LPC_{RSUquiz}$	Payment to QSE for providing Balancing Energy Up from a specific unit to solve Local Congestion per QSE per interval per zone
$LPC_{RSUqviz}$	Payment to QSE for providing Balancing Energy Up from Aggregated Units to solve Local Congestion per QSE per interval per zone
$LBEAGR_{ivq}$	The percentage of the aggregated instructions to the Aggregated Unit that represents the OOM Energy market
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions for that interval per specific unit
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions for that interval per specific unit
$MCPE_{iz}$	Market Clearing Price for Energy per interval per zone
MR_{qiuz}	Meter reading per unit per interval
MR_{qivz}	Meter reading per Aggregated Unit per interval
$NETLBEDQ_{ivq}$	The net of all unit specific Local Balancing Energy Instructions

	(Down minus Up) that result in a positive value
$NETLBEUQ_{ivq}$	The net of all unit specific Local Balancing Energy Instructions (Up minus Down) that result in a positive value
$NETOOMDEQ_{ivq}$	The net of all unit specific OOM instructions (Down minus Up) that result in a positive value
$NETOOMUEQ_{ivq}$	The net of all unit specific OOM instructions (Up minus Down) that result in a positive value
$NETUEQ_{ivq}$	The overall net direction per the instructions given to the Aggregated Unit results in an up direction
OL_{qiuz}	Resource Plan output level submitted by the QSE for the specific unit given the unit-specific instruction for that interval
OL_{qivz}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the unit given the unit-specific instruction for that interval
PM_{qiuz}	Incremental Premium Specified for that specific unit per interval
PM_{qivz}	Incremental Premium Specified for that specific Aggregated Unit per interval

(a) The Nodal Market implementation requires Early Delivery System (EDS) testing. During the EDS 3 R6.3 Load Frequency Control (LFC) testing as documented by ERCOT's issuance of Dispatch Instructions to perform the test, the formula in Section 7.4.3.1(1) will be modified in the following way:

$$I_{OOMUPiuq} = ¼ * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$I_{OOMDNiuq} = ¼ * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEUQ_{qui} = ¼ * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEDQ_{qui} = ¼ * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Up deployment.
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment.
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Up deployment.
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Down deployment.
BP_{y}	Base Point by interval - The Base Point generated from SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute

Settlement Interval where an OOME or Local Balancing Energy deployment occurred.

TLMP $_y$	Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
y	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
i	15-minute Settlement Interval.
u	Individual Generation unit (including units within an Aggregated Unit).
q	QSE.

(i) During EDS 3 R6.3 LFC testing, when a combined cycle Resource receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate the OOME or Local Balancing Energy Instruction, as calculated in Section 7.4.3.1(1)(a) above, to each individual unit making up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

(2) Whenever a LaaR with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Up, is deployed to solve Local Congestion, the QSE will be paid the incremental premium specified as defined below:

$$\mathbf{LPC_{LAARquiz} = -1 * \Sigma\ ((PM_{qiuz} - MCPE_{iz}) * Max\ (0, Min\ (OL_{qiuz} - LAARTOT_{qiuz}, OL_{qiuz} - IOL_{qiuz})))}$$

$$PM_{qiuz} = Max\ (FBPM_{qiuz}, MCPE_{iz})$$

$$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$$

Where:

i	interval
q	QSE

u	individual LAAR unit
z	zone
BPM_{qiuz}	Incremental bid premium for that specific LaaR unit per interval
$FBPM_{qiuz}$	Incremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The Instructed output level for the LaaR unit given the unit-specific instruction
$LAARTOT_{qiuz}$	Actual ESI ID usage per unit per interval
$LPC_{LAARquiz}$	Payment to QSE for providing Balancing Energy Up from specific LaaR unit to solve Local Congestion per QSE per interval per zone
$MCPE_{iz}$	Market Clearing Price for Energy per interval per zone
OL_{qiuz}	Resource Plan output level submitted by the QSE for the specific LaaR unit given the unit-specific instruction for that interval
PM_{qiuz}	Incremental Premium specified for that specific LaaR unit per interval

7.4.3.2 Balancing Energy Down from a Specific Resource

In accordance with Section 6.7.1.2, Deployment of Balancing Energy when Congestion Occurs, whenever a specific Generation Resource with a submitted bid premium, in accordance with the Resource Category Generic bid limit for Balancing Energy Down, is deployed decrementally to solve Local Congestion, the QSE will be paid the difference between the MCPE of the Congestion Zone in which the specific Generation Resource is located, and the decremental bid premium specified.

The calculation of the payment for Balancing Energy Down from a specific Resource is as follows:

$$\mathbf{LPC_{RSDquiz} = -1 * \Sigma(MAX(0,(MCPE_{iz} - PM_{qiuz})) * Max(0, Min(OL_{qiuz} - MR_{qiuz}, OL_{qiuz} - IOL_{qiuz})))_u}$$

$$\mathbf{LPC_{RSDqviz} = -1 * \Sigma(MAX(0,(MCPE_{iz} - PM_{qivz})) * Max(0, Min(OL_{qivz} - MR_{qivz}\ NETDEQ_{ivq})))_v * LBEAGR_{ivq}}$$

For gas-fired units:

$FBPM_{qiuz} = (BPM_{qiuz} / FIP_{d-1}) * FIP_d$

$PM_{qiuz} = FBPM_{qiuz}$

$PM_{qivz} = Max(PM_{qiuz})$

For all other Resource categories:

$PM_{qiuz} = BPM_{qiuz}$

$PM_{qivz} = Max(PM_{qiuz})$

$NETDEQ_{ivq}$	=	Max [0, $((NETOOMDEQ_{ivq} + NETLBEDQ_{ivq}) - (NETOOMUEQ_{ivq} + NETLBEUQ_{ivq}))$]
$NETOOMUEQ_{ivq}$	=	Max [0, $(SUM(I_{OOMUPqui})_u - SUM(I_{OOMDNqui})_u)$]
$NETLBEUQ_{ivq}$	=	Max [0, $(SUM(LBEUQ_{qui})_u - SUM(LBEDQ_{qui})_u)$]
$NETOOMDEQ_{ivq}$	=	Max [0, $(SUM(I_{OOMDNqui})_u - SUM(I_{OOMUPqui})_u)$]
$NETLBEDQ_{ivq}$	=	Max[0, $(SUM(LBEDQ_{qui})_u - SUM(LBEUQ_{qui})_u)$]
$LBEAGR_{ivq}$	=	$[SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u] / [SUM(LBEUQ_{qui})_u + SUM(LBEDQ_{qui})_u + SUM(I_{OOMUPqui})_u + SUM(I_{OOMDNqui})_u]$

Where:

d	Operating Day of interval i
i	interval
q	QSE
u	individual Generation unit (including units within an Aggregated Unit)
v	Aggregated Unit
z	zone
BPM_{qiuz}	Decremental bid premium specified for that specific unit per interval
$FBPM_{qiuz}$	Decremental bid premium, adjusted for fuel price, for that specific unit per interval
FIP_d	Fuel Index Price for Operating Day of interval i
FIP_{d-1}	Fuel Index Price used to calculate Resource category bid limits effective for Operating Day of interval i
IOL_{qiuz}	The instructed output level for the unit given a unit-specific instruction
$I_{OOMDNqui}$	OOM Energy Down instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$I_{OOMUPqui}$	OOM Energy Up instructions for that interval for that unit converted to MWh for that interval by dividing by the interval count per hour (4 per hour for 15 minute Settlement Interval)
$LBEAGR_{ivq}$	The percentage of the aggregated instructions to the Aggregate Unit that represents the OOM Energy market.
$LBEDQ_{qui}$	Local Balancing Energy Down instructions for that interval per specific unit
$LBEUQ_{qui}$	Local Balancing Energy Up instructions for that interval per specific unit
$LPCRSD_{quiz}$	Payment to QSE for providing Balancing Energy Down from a specific unit to solve Local Congestion per QSE per interval per zone
$LPCRSD_{qviz}$	Payment to QSE for providing Balancing Energy Down from Aggregated Units to solve Local Congestion per QSE per interval per zone
$MCPE_{iz}$	Market Clearing Price of Energy per interval per zone
MR_{qiuz}	Meter reading per unit per interval.
MR_{qivz}	Meter reading per Aggregated Unit per interval.

$NETDEQ_{ivq}$	The overall net direction per the instructions given to the Aggregated Unit results in a down direction
$NETLBEDQ_{ivq}$	The net of all unit specific Local Balancing Energy instructions (Down minus Up) that result in a positive value.
$NETLBEUQ_{ivq}$	The net of all unit specific Local Balancing Energy instructions (Up minus Down) that result in a positive value.
$NETOOMDEQ_{ivq}$	The net of all unit specific OOM instructions (Down minus Up) that result in a positive value.
$NETOOMUEQ_{ivq}$	The net of all unit specific OOM instructions (Up minus Down) that result in a positive value.
OL_{qiuz}	Resource Plan output level submitted by the QSE for the unit given the unit-specific instruction for that interval
OL_{qivz}	Resource Plan output level submitted by the QSE for the Aggregated Unit containing the unit given the unit-specific instruction for that interval
PM_{qiuz}	Decremental Premium for that specific unit per interval
PM_{qivz}	Decremental Premium for that specific Aggregated Unit per interval

(a) The Nodal Market implementation requires Early Delivery System (EDS) testing. During the EDS 3 R6.3 Load Frequency Control (LFC) testing documented by Dispatch Instruction to the QSE for a specific test period, the formula in Section 7.4.3.2 will be modified in the following way:

$$I_{OOMUPiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$I_{OOMDNiuq} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEUQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

$$LBEDQ_{qui} = \frac{1}{4} * (\sum_{y} ((BP_{y} + BP_{y-1})/2 * TLMP_{y}) / (\sum_{y} TLMP_{y}))$$

Where:

$I_{OOMUPiuq}$	OOM Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Up deployment.
$I_{OOMDNiuq}$	OOM Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with an OOME Down deployment.
$LBEUQ_{qui}$	Local Balancing Energy Up Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Up deployment.
$LBEDQ_{qui}$	Local Balancing Energy Down Instructions - The Generation Resource's aggregated Base Point for the 15-minute Settlement Interval corresponding with a Local Balancing Energy Down deployment.

BP_y	Base Point by interval - The Base Point generated from SCED test system for the Generation Resource for the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
$TLMP_y$	Duration of SCED interval per interval - The duration of the portion of the SCED interval *y* within a 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
y	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval where an OOME or Local Balancing Energy deployment occurred.
i	15-minute Settlement Interval.
u	Individual Generation unit (including units within an Aggregated Unit).
q	QSE.

(i) During EDS 3 R6.3 LFC testing, when a combined cycle plant receives SCED Base Points at the Combined Cycle Configuration (as defined in the ERCOT Nodal Protocols) level, ERCOT will use MW telemetry based splitting percentages to allocate the OOME or Local Balancing Energy Instructions, as calculated in Section 7.4.3.2(1)(a) above, to each individual unit making up the Combined Cycle Configuration for each 15-minute Settlement Interval.

(ii) If, after receiving the Initial Statement for the Operating Day on which EDS 3 R6.3 LFC testing occurred as documented by Dispatch Instruction(s) to the QSE for a specific test period, a QSE does not agree with the updated Instructed Output level or payment for OOME or Local Balancing Energy, a QSE may submit a settlement and billing dispute in accordance with the process outlined in Section 9.5, Settlement and Billing Dispute Process. In addition to the standard information required on the dispute form, the dispute should clearly reference the EDS 3 R6.3 LFC test and indicate the disputed Settlement Intervals involved in the test.

7.4.3.3 Balancing Energy Charge to Solve Local Congestion

In accordance with this section, all the cost associated with Balancing Energy from a specific Resource to solve Local Congestion will be allocated on a QSE Load Ratio Share.

$$\mathbf{LCC_{iq} = -1 * \Sigma ((LPC_{RSUqiz} + LPC_{RSDqiz}) * LRS_{iq})}$$

Where:

LPC_{RSUqiz}	Payment to QSE for providing Balancing Energy Up from specific Resource to solve Local Congestion per QSE per interval per zone

LPC_{RSDqiz}	Payment to QSE for providing Balancing Energy Down from specific Resource to solve Local Congestion per QSE per interval per zone
LCC_{iq}	Local Congestion Load allocation charge per QSE per interval
LRS_{qi}	Load Ratio Share

7.4.4 *Direct Assignment of Local Congestion Costs*

ERCOT shall directly assign Local Congestion costs beginning six months after ERCOT's incurred costs of clearing Local Congestion during a rolling twelve month period reaches 20 million dollars.

[PRR492 & PRR532: Add Section 7.4.5 upon system implementation and filling staffing requirements:]

7.4.5 Plan to Alleviate Chronic Local Congestion Charges

(1) ERCOT shall monitor Local Congestion Area costs and post a report on the MIS ten (10) days following the end of the month. The report shall include the amount of Local Congestion Area costs by type of payment to Resources (e.g., OOME Up, OOME Down, and OOMC) including discussion of the limiting transmission element(s) or other significant events that may have contributed to Local Congestion as available. This information will also be reported monthly to the ERCOT Board of Directors, PUCT Market Oversight Division, and appropriate ERCOT subcommittees.

(2) For the purposes of this section, "Local Congestion Area" is defined as a sub-region of a Congestion Zone in which ERCOT dispatches OOME, OOMC, or local Balancing Energy Service on a regular basis as described in the ERCOT monthly report of Local Congestion Cost.

(3) If the amount of OOME, OOMC, or local Balancing Energy Service in a Local Congestion Area exceeds a threshold amount of either ten million dollars ($10 million) during the most current twelve (12) consecutive months or five million dollars ($5 million) in the most current three (3) consecutive months, ERCOT shall report such to the ERCOT Board, PUC Market Oversight Division, and appropriate ERCOT subcommittees and shall initiate a study to identify feasible alternatives that may, at a future time, be more economically efficient than the continued use of OOME, OOMC, or local Balancing Energy Service.

(4) ERCOT shall develop feasible alternatives and their associated costs to reduce or replace the use of OOME, OOMC, or local Balancing Energy Service. At a minimum, the list of feasible alternatives that ERCOT shall include consideration of a new CSC for the following year under Section 7.2.1.1, Process for Determining CSCs, item (2), a change in ERCOT operations affecting the Local Congestion, construction of new or expansion of existing Transmission Facilities, installation of voltage control devices, more accurate modeling of transmission line or transformer MVA Real Time limits, solicitation or auctions for interruptible Load from Load Serving Entities when such Protocols are

available, or continued use of OOME, OOMC, or local Balancing Energy Service.

(5) ERCOT shall prepare a report, no later than forty-five (45) days after the threshold is exceeded, on the feasible alternatives available to reduce Local Congestion below the threshold amount. The report shall include:

(a) The root cause of the Local Congestion;

(b) Current actions of the TDSP and/or ERCOT to relieve such Local Congestion;

(c) A review of ERCOT's operations (e.g., Dispatch Instructions, transmission line limits, etc.);

(d) A determination of short term mitigation measures that could reduce the use of OOME, OOMC or local Balancing Energy Service; and

(e) The amount of market impact caused by the Local Congestion.

The report shall also include an implementation plan, timeline, and recommendations regarding short-and long-term solutions to the Local Congestion as appropriate. The implementation plan may identify studies to be conducted prior to recommendations for short- and long-term solutions to the Local Congestion. These additional studies will be conducted through the regional planning process, as appropriate.

(6) This report shall be posted on the MIS and provided to the PUCT Market Oversight Division, the appropriate ERCOT subcommittee(s), and ERCOT Board of Directors.

(7) Subsequent to the initial report, ERCOT staff shall provide monthly updates on the schedule and planning status to the PUCT Market Oversight Division, appropriate ERCOT subcommittee(s), and the Board. ERCOT will use its best efforts to implement short- and long-term solutions as quickly as practical.

7.5 Transmission Congestion Rights

Pre-assigned Congestion Rights (PCRs) are priced differently than Transmission Congestion Rights (TCRs), and PCRs are allocated rather than awarded as a result of the annual TCR auction process. The eligibility, pricing and annual allocation of PCRs are addressed in Section 7.5.6, Direct Allocation of Pre-assigned Congestion Rights. For all other purposes, PCRs are functionally and financially equivalent to TCRs.

7.5.1 Function of Transmission Congestion Rights

TCRs and PCRs function as financial hedges (similar to financial options with zero strike price) against the marginal costs to resolve Zonal Congestion. The total costs of Zonal Congestion comprise those portions of Replacement Reserve Service (RPRS) costs and the Balancing

Energy service costs associated with managing Zonal Congestion. The TCR and PCR holder will receive an amount equal to the directly assigned Congestion costs for an equivalent quantity of scheduled flow. TCRs are not deratable once they are sold in the auction(s), and allocated PCRs are not deratable.

A TCR is a financial right on a specified directional Commercially Significant Constraint (CSC) for a particular hour that entitles the holder of record to receive remuneration equal to the sum of non-negative Balancing Energy service and RPRS Shadow Prices ($/MW/15-minute) over all 15-minute intervals within the hour for the corresponding CSC multiplied by 1 MW.

7.5.2 Procedure for Computation of Transmission Congestion Rights Quantities

The ERCOT System will be modeled and the CSC interfaces determined in accordance with Section 7.2, CSC Zone Determination Process, using steady-state and dynamic power system simulation software. The capacity of the CSCs will be fully used and there will be no reservation of capacity for any particular segment of Load.

ERCOT will determine CSC Limits as follows:

(1) Determine the pre-contingency flow limit on the directional CSC that results in the CSC or any directional Clostely Related Element (CRE) corresponding to the CSC becoming the base case limiting element, for all Congestion Zone-to-Congestion Zone transfer studies.

(2) Determine the pre-contingency flow limit on the directional CSC to withstand any single contingency that results in any directional CRE, including elements comprising the CSC, corresponding to the CSC to become the post-contingency limiting element for all Congestion Zone-to-Congestion Zone transfer studies.

(3) The lower of the CSC flow limits from (1) and (2) above sets the CSC Limit.

7.5.2.1 Annual TCR Quantities

Annually determined Summer ERCOT peak flow limits for CSCs will provide the starting basis for determining the number of TCRs to be auctioned. The flow limit established for each CSC on an annual basis may vary from time to time based on changes in system conditions. The ultimate number of TCRs to be auctioned for the CSCs will take into account forecasted changes in system conditions.

ERCOT will determine the total annual quantity of TCRs for the annual distribution by adjusting the annual summer peak base case CSC Limits by the following amount for each CSC: the sum over all nodes of the product of the expected level of Load at each node from the annual summer peak base case multiplied by the difference between the corresponding Shift Factor for that node and CSC and a modification of the Zonal Shift Factor calculated using all Generation Resources.

7.5.2.2 Monthly TCR Quantities

ERCOT will determine the total quantity of TCRs for the monthly distribution by adjusting the corresponding modified seasonal base case CSC Limits by the following amount for each CSC: the sum over all nodes of the product of the expected level of Load at each node from the modified seasonal base case multiplied by the difference between the corresponding Shift Factor for that node and CSC and a modification of the Zonal Shift Factor calculated using all Generation Resources. The modified seasonal base case for a particular month will be based on the most limiting situation within the corresponding month. This analysis takes into account all transmission outages of significant duration and impact with the objective of collecting sufficient revenues from direct assigned Congestion costs to pay all TCR holders.

ERCOT may distribute TCRs in amounts less than the total quantities based on expectations of the frequency and magnitude of potential CSC de-rates that could occur during any particular month.

7.5.2.3 ERCOT Posting of TCR Quantities

Upon review and approval of the TCR amount, ERCOT will determine and post on the Market Information System (MIS) the total quantity, the amount of PCRs, and the remaining available quantity of TCRs for each CSC. The remaining available quantity of TCRs for auction will be the total amount of TCRs less the amount of PCRs.

7.5.3 Annual and Monthly Auction of Transmission Congestion Rights

7.5.3.1 Annual and Monthly Auction Summary

Forty percent (40%) of the total annual quantity of TCRs less PCRs for any given CSC will be awarded to Market Participants based on the results of an initial annual auction. These TCRs will be made available in the annual auction for each hour of the year. For the annual auction, the quantity of TCRs used to calculate the 25% limit, pursuant to Section 7.5.9, Limitation on Ownership or Control of TCRs, is based on the total annual quantity of TCRs (which includes PCRs). Each annual auction will be completed no later than the 15th of December, on a date set by ERCOT.

Prior to each monthly auction, ERCOT will determine the total monthly quantity of TCRs available for that month based upon forecasted system conditions for the month. The amount of TCRs that will be auctioned in the monthly auction will be the total monthly quantity of TCRs, less any PCRs, and less any TCRs for that month sold in the annual auction. For that monthly auction, the quantity of TCRs used to calculate the 25% limit, pursuant to Section 7.5.9, Limitation on Ownership or Control of TCRs, is the greater of (A) the total annual quantity of TCRs, or (B) the total monthly quantity of TCRs. However, in determining the amount of TCRs available in each monthly auction, ERCOT shall seek to achieve revenue neutrality and avoid a revenue shortfall due to payment to TCR holders for the month. The TCRs auctioned in the monthly auction will be awarded to Market Participants based on the results of monthly auctions.

These TCRs will be made available in the monthly auction for all hours of each day of each month for which the auction is being held. Each monthly auction will be completed no later than the 15th of each month prior to the month that the TCRs are effective, on a date set by ERCOT.

7.5.3.2 Auction Procedures

ERCOT will develop a procedure for authenticating ownership for each TCR.

ERCOT, or its designee, will conduct a single-round, simultaneous combinatorial auction for selling the TCRs available for each annual or monthly auction for all CSCs. ERCOT shall use a standard linear programming model to maximize the auction revenue subject to the constraints that ERCOT and the bidders provide prior to the start of the auction. The clearing-price for each TCR will be equal to the corresponding Shadow Price of the marginal TCR awarded on that CSC.

The auction process will be open to any qualified TCR Account Holder. To participate in the auctions, a bidder must meet financial security requirements established by ERCOT and must have access to the computer hardware, software and communications equipment required to participate.

7.5.3.2.1 TCR Auction Notices

No less than twenty-days (20) prior to the annual auction and ten (10) days prior to the monthly auction, ERCOT will post:

(1) The Zonal Shift Factor and zone-to-zone impact matrix (to determine the megawatt impact on each CSC);

(2) The number of TCRs to be issued for each period (annual, monthly) in that auction;

(3) The number of PCRs that have been allocated for each CSC;

(4) Deadline for bidders to satisfy financial requirements;

(5) Specifications for the equipment necessary to participate in the auction;

(6) The date and time by which bids must be submitted;

(7) The bid format;

(8) CSCs and CREs;

(9) Any other information of commercial significance to bidders; and

(10) The total number of TCRs available and used to determine the 25% limit, pursuant to Section 7.5.9, Limitation on Ownership or Control of TCRs.

7.5.3.2.2 Auction

The auction will be a single-round, simultaneous combinatorial auction for selling the TCRs available for an annual or monthly auction for CSCs, with the following steps:

(1) The following constraints shall be entered into ERCOT's auction engine model:

(a) The maximum number of TCRs for any given CSC available for auction.

(b) The maximum number of TCRs for each CSC that a bidder may purchase in the auction that will ensure the bidder will not exceed the lower of the TCR limitation described in Section 7.5.9, Limitation on Ownership or Control of TCRs, or a bidder's self-imposed TCR limit set by the bidder prior to the auction.

(c) The bidder's credit limit approved by ERCOT or, if provided, the bidder's self-imposed maximum credit Obligation will be enforced as a constraint such that the summation over all bids of the product of the awarded TCRs and the bidder's bid price is less than or equal to the lower of the bidder's self-imposed maximum Obligation or the credit limit approved by ERCOT. The bidder's self-imposed maximum credit Obligation cannot exceed the credit limit approved by ERCOT.

(d) Bids may be submitted for TCRs for any individual CSC and for weighted combinations of CSCs. Each bid must be non-negative and shall contain the maximum quantity of TCRs, the maximum price, and the distribution weights of the TCRs among the CSCs. The distribution weight shall be submitted with non-negative ratios (with up to three decimal places) that sum to one (1.000), as illustrated in the table below.

Examples of Allowable Bids

Bidders and Bids	CSC 1 Weighting	CSC 2 Weighting	CSC 3 Weighting	Bid Price ($ per MWh)	Maximum Quantity (TCRs)
A1	0.2	0.3	0.5	$10.00	300
A2	1.0	0.0	0.0	$5.00	185
B	0.2	0.5	0.3	$11.25	250
C1	0.6	0.3	0.1	$7.50	240
C2	1.0	0.0	0.0	$1.00	100
D1	0.0	0.5	0.5	$9.50	320
D2	0.0	1.0	0.0	$3.00	140
D3	0.0	0.0	1.0	$2.50	170

NOTE: 3 decimal places for weightings and bid price allowable.

(2) The auction system will award a combination of TCRs that maximizes the sum of bid prices times the awarded MW for the respective bids while simultaneously observing all

applicable constraints. ERCOT shall award TCRs in quantities rounded to three decimal places.

(3) The TCR clearing price for a CSC will be equal to the corresponding Shadow Price of the marginal TCR awarded on that CSC. The Shadow Price is representative of the decremental bid-based revenue that would be produced from the TCR auction if one less TCR were available to be auctioned on that CSC.

(4) If all of the annual TCRs available for a CSC in the annual auction are not awarded (excluding fractional rounding), the TCR clearing price for that CSC shall be determined to be zero (0.0) dollars per MWh. The TCRs not awarded/purchased in the annual auction will be included in the monthly auction.

(5) If all of the TCRs available for a CSC in the monthly auction are not awarded (excluding fractional rounding), the TCR Clearing Price for that CSC shall be determined to be zero (0.0) dollars per MWh. The TCRs not awarded/purchased in the monthly auction will not be sold. Payments for TCR and PCR Invoices shall be due five (5) Bank Business Days after issuance of the Invoice. Any unpaid TCRs and PCRs that remain outstanding after their Invoice date shall be forfeited by the awardees and, with respect to TCRs and PCRs from the annual auction, included in the following monthly auctions.

(6) The linear programming solution will solve for one optimal solution, which may result in some bids at the clearing price not being awarded a TCR. This situation may be minimized because bid prices and bid ratios can be submitted with up to three decimal places.

(7) The auctioneer shall announce the results of the auction simultaneously to all TCR bidders, by posting the results on the MIS. For each CSC, the total quantity of TCRs awarded, the TCR clearing price, and list of all bids will be posted. The identity of the bidders will not be posted.

(8) When an Entity is awarded TCRs as a result of an auction, the TCRs will not become the property of the awardees and the TCRs will not be placed in their accounts until the TCR Invoices have been paid in full. TCRs awarded are considered when determining ownership. Ownership of TCRs in a secondary transfer does not change until the recipient accepts the transfer. Until such time, the initiator of the secondary transfer is considered the owner of the TCRs.

(9) The twenty-five percent (25%) limit shall be applied to secondary transfers. When a recipient accepts a secondary transfer, the number of TCRs the recipient owns in any hour for a given CSC during the month will be added to the amount of the TCRs they will receive as a result of the secondary transfer. If the total exceeds a bidder's twenty-five percent (25%) limit for the CSC, the secondary transfer shall be cancelled. Electronic Notice shall be given to the secondary transfer initiator and recipient of the cancellation.

7.5.4 Allocation Method and Timing for Distributing TCR Auction Revenues

The TCR auction revenues from each annual auction and PCR revenues will be divided into monthly revenues in the same proportion as ERCOT's monthly energy forecast. This amount will be added to the monthly auction revenue. The total monthly revenues from the auctions will be credited to QSEs once per month on a monthly Load Ratio Share for the ERCOT peak operating interval during the month basis. These revenues will be paid to QSEs no later than the 15th of the following month. PCR holders will be issued invoices that are based on 15 percent of the TCR clearing price from the annual auction. Payment of these invoices is required prior to the distribution of PCRs.

Any difference between the directly assigned Congestion costs charged by ERCOT and Zonal Congestion credits paid to TCR holders for any 15-minute interval will be credited or charged to all QSEs on a Load Ratio Share basis for the same 15-minute interval. ERCOT shall provide a report to be published on its MIS which details by interval, any Zonal Congestion revenue shortfalls or surpluses. The report shall be published on a monthly basis within seven (7) Business Days of the end of a month for the prior month's activity. The report shall provide a description of the methodology and billing determinants used to determine and assess any revenue shortfalls or surpluses, and shall include any billing determinants necessary to replicate the results in the report, to the extent such billing determinants are not already available.

7.5.5 TCR Settlement

To participate in ERCOT's TCR settlements, a TCR holder need not be a QSE nor be represented by a QSE, but must be registered as a TCR Account Holder with ERCOT and have the ability to make and accept electronic transfer of funds.

$$TCRUL_{nq} = -1 * \left(MAUCR_n + AAUCR * \frac{MEnergy_n}{\sum_{All\ Months} MEnergy_n} \right) * LSR_{nq}$$

Where:

n	Month
q	QSE
$TCRUL_{nq}$	TCR Auction Revenue Uplift per QSE per month
$MAUCR_n$	Monthly TCR Auction Revenue
$AAUCR_n$	Annual TCR Auction Revenue plus PCR revenues
$Menergy_n$	Monthly Energy Forecast
LSR_{nq}	QSE's Load Share Ratio in that month's peak interval

Congestion credits, calculated as described below, will be determined based on the record of ownership in ERCOT's database, at the end of the day for which the TCRs are effective, for the relevant CSC, based on the published Shadow Price(s) for the same. The TCR holders will be paid Congestion credits based on their TCR ownership the day after direct assigned Invoice payments are due in accordance with the Settlement Calendar in Section 9, Settlement and Billing.

$$\mathbf{TCRPAY_{hp}} = -1 * \Sigma\, (TCR_{CSChp} + PCR_{CSChp}) * (\Sigma\, (SP_{CSCi}/4)_i + SPC_{CSCh}))_{CSC}$$

Where:

h	Hour being calculated
i	Intervals within the hour
p	TCR owner of record
CSC	Commercially Significant Constraint
CSC_{RPiq}	CSC Replacement Reserve related Congestion charge, per interval, per QSE
TCR_{CSChp}	Total number of TCRs owned per hour, per TCR owner of record
PCR_{CSChp}	Total number of PCRs owned per hour, per PCR owner of record
SP_{CSCi}	BES Shadow Price per CSC, per interval
SPC_{CSCh}	RPRS Capacity Shadow Price per CSC, per hour
$TCRPAY_{hp}$	TCR payment per hour, per TCR owner of record

7.5.6 Direct Allocation of Pre-assigned Congestion Rights

Upon the zonal method being implemented and once auctioned TCRs are available for use, Municipally Owned Utilities (MOUs) and Electric Cooperatives (ECs) which own or have a long-term (greater than five (5) years) contractual commitment for annual capacity and energy from a specific remote Generation Resource, and that commitment was entered into prior to September 1, 1999, are eligible for PCRs. In addition, MOUs and ECs which have a long-term (greater than five (5) years) allocation from the federal government for annual capacity and energy produced at a federally-owned hydroelectric Generation Resource, and that allocation was in place prior to September 1, 1999, are eligible for PCRs. The PCRs will be allocated as follows:

(1) PCRs are available on an annual basis until the date upon which a MOU or EC implements retail Customer Choice, or, alternatively, until such other date as may be specified by Order of the Public Utility Commission of Texas (PUCT). Non Opt-In Entities (NOIEs) that opt in after the first of the year shall pay a pro rata share of the full value for remaining months: (Applicable Annual TCR Clearing Price * 85% * Quantity of PCRs * Number of hours remaining in the year).

(2) The cost of PCRs shall be equal to fifteen percent (15%) of the applicable annual TCR auction clearing price for each CSC for which a PCR is allocated.

$$\mathbf{PCRINV_{yp}} = \Sigma\, ((ATCRCP_{CSCyp} * .15) * PCR_{CSCyp} * H))_{CSC}$$

Where:

p	PCR owner of record

y	Year
ATCRCP	Annual TCR Clearing Price ($/MW)
CSC	Commercially Significant Constraint
H	Number of Hours eligible for PCRs (hours/year)
PCR_{CSCyp}	Total number of PCRs allocated for each of the CSCs, per PCR owner of record, for a given year (MW)
$PCRINV_{yp}$	TCR payment per hour, per TCR owner of record ($/year)

(3) The allocation of PCRs to any single Entity shall not exceed twenty-five percent (25%) of the total available TCRs at a CSC interface for any single direction.

(4) The distribution of PCRs will be sufficient to isolate the MOUs and ECs from any direct-assigned costs associated with transporting the output of their remote Generation Resources to their native Load.

(5) ERCOT shall distribute PCRs and accordingly populate the TCR ownership database for those months where the NOIE meets eligibility requirements. PCRs will be included in applicable monthly TCR auctions when the NOIE does not meet eligibility requirements across the year.

(6) PCRs may be traded in the secondary market.

(7) Holders of PCRs shall not be precluded from participating in the market to purchase additional TCRs.

7.5.7 Secondary Market Exchange of Transmission Congestion Rights

Market Participants can exchange TCRs and PCRs in any secondary market. ERCOT will initially populate a database of hourly TCR holders with the annual and monthly first-purchasers of TCRs and hourly PCR holders. Subsequent holders or owners (other than first-purchasers) of the TCRs and PCRs who want the change in ownership to be recorded in the ERCOT TCR ownership database will be responsible for assuring that the sellers report the transactions to ERCOT's satisfaction and that the sellers authorize the transaction within the ERCOT database in accordance to ERCOT's procedures. A TCR and PCR may change ownership in the ERCOT TCR ownership database through the end of the Adjustment Period of the Operating Hour for which it is designated to hedge Congestion costs.

7.5.8 Transmission Congestion Right Value Under Physical Curtailment or De-rating

TCRs and PCRs will retain their full value even in the event of physical curtailment or flow limitation below the megawatt quantity for which TCRs were defined on any given CSC path.

7.5.9 *Limitation on Ownership or Control of TCRs*

(1) No Entity combined with its Affiliates may, either directly or indirectly, own, control, or receive the revenue from more than twenty-five percent (25%) of the total available TCRs and/or PCRs at a CSC interface for any single direction for a given hour. The total available TCRs for the annual auction and each monthly auction are determined pursuant to Section 7.5.3.1, Annual and Monthly Auction Summary, and included in the Auction Notice posted pursuant to Section 7.5.3.2.1, TCR Auction Notices.

(2) For purposes of this Section, the total number of TCRs available at a CSC interface for any single direction for a given hour is the greater of (a) the total quantity of TCRs available for annual distribution for that CSC interface, direction, and hour, as determined under Section 7.5.2.1, Annual TCR Quantities, or (b) the total quantity of TCRs for the monthly distribution for that CSC interface, direction, and hour, as determined under Section 7.5.2.2, Monthly TCR Quantities.

(3) If an Entity engages in a transaction with a counter-party, whereby the total ownership or control of the combined Entities exceeds the twenty-five percent (25%) limitation, then any TCRs owned by the counter-parties are not, solely by virtue of that transaction, included in the TCRs that the Entity combined with its Affiliates owns, or controls.

7.5.10 *Transition of Transmission Congestion Rights to Congestion Revenue Rights*

ERCOT will refund to TCR/PCR owners the annual TCR/PCR auction revenues and monthly TCR auction revenues for all remaining days of the year that follow the Texas Nodal Market Implementation Date. ERCOT will make refunds to TCR/PCR owners no later than thirty (30) Business Days following the start of the Texas Nodal Market.

The total refund of auction revenues to a TCR/PCR owner of record is calculated as follows:

$$\mathbf{TCRRAMT_p = -1 * (TCRMR_p + TCRAR_p + TCRRR_p)}$$

ERCOT shall refund each TCR owner of record its awarded monthly TCRs that are no longer effective for the month of Texas Nodal Market Implementation, calculated as follows:

$$\mathbf{TCRMR_p = MAUCR_p * MRP}$$

ERCOT shall refund each TCR/PCR owner of record its awarded annual TCRs/PCRs that are no longer effective for the month of Texas Nodal Market Implementation, calculated as follows:

$$\mathbf{TCRAR_p = AAUCR_p * (MEnergy_m / (} \sum_{All\ Months} MEnergy_n \mathbf{) * MRP}$$

ERCOT shall refund each TCR owner of record any remaining annual TCRs/PCRs for all months following the month of the Texas Nodal Market Implementation, calculated as follows:

$$\mathbf{TCRRR_p = AAUCR_p * (\sum_{n>m} MEnergy_n / (\sum_{All\ Months} MEnergy_n))}$$

Where:

TCRRAMT	TCR/PCR Refund Amount per TCR/PCR owner of record
TCRMR	TCR Monthly Refund amount per TCR owner of record for the month of Texas Nodal Market Implementation
TCRAR	TCR/PCR Annual Refund amount per TCR/PCR owner of record for the month of Texas Nodal Market Implementation
TCRRR	TCR/PCR Annual Remaining Refund amount per TCR/PCR owner of record for the months following Texas Nodal Market Implementation
MRP	Monthly Refund Percentage calculated as the number of days remaining in the Texas Nodal Market Implementation month divided by the total number of days in the Texas Nodal Market Implementation month
MEnergy	Monthly Energy Forecast
MAUCR	Monthly TCR Auction Revenue for the month of the Texas Nodal Market Implementation
AAUCR	Annual TCR/PCR Auction Revenue
n	Month
m	Month of Texas Nodal Market Implementation
P	TCR/PCR owner of record

7.6 Incorporation of Reliability Must-Run and Out of Merit Order Resources

RMR and OOM Resources will be used for Congestion Management as described in Sections 4, Scheduling, Section 5, Dispatch and Section 6, Ancillary Services. RMR and OOM Resources will be used for Congestion Management only in the absence of bid-based solutions to alleviate Local Congestion. RMR and OOM Resources will be compensated in accordance with Section 6.8, Compensation for Services Provided.

7.7 Remedies to Congestion Through Transmission Expansion

ERCOT will review the cost of correcting localized transmission limitations through new construction or other means, and will compare this to the costs incurred to correct those problems. ERCOT shall publish the average cost of the constraint by period for each transmission limitation subtotaled by TDSP. This information will be included in ERCOT's Annual Transmission Planning Report. If the projected or actual cost of ERCOT directed Congestion Management including all energy and capacity tools, is greater than the cost of correcting the transmission limitations through construction of Facilities, then ERCOT may recommend an upgrade of Facilities to the TDSP.

7.8 Congestion Management in McCamey Area

The purpose of this Section is to minimize uplifted Congestion costs while attempting to reliably maximize the use of the transmission system in the McCamey Area.

7.8.1 Determination of McCamey Area

(1) The McCamey Area is an area of west Texas in which an abundance of wind-powered generation causes Local Congestion.

(2) ERCOT shall identify wind-powered Generation Resources (WPGRs) in the McCamey Area that:

(a) have significant impact upon the most limiting local Operational Constraint, and

(b) cannot operate their Facilities at full capacity simultaneously with other WPGRs in the McCamey Area when all local transmission lines are in service without violating ERCOT reliability criteria.

(3) ERCOT shall post a current map of the boundaries of the McCamey Area containing those WPGRs on the ERCOT website. ERCOT shall revise the map as necessary to reflect any changes in transmission system configuration or new interconnections of WPGRs in West Texas.

(4) TGRs will be allocated only to Wind Powered Generation Resources in the McCamey Area.

7.8.2 Determination of Generation Limits

ERCOT shall periodically calculate the amount of generation that can be reliably operated within the McCamey Area considering the projected Dispatch of the total generating capacity in the McCamey Area, including any RMR Unit located in the McCamey Area, and any other factors that may affect the amount of local transmission transfer capability from the McCamey Area. ERCOT shall post the results of this calculation for an Operating Day in the Day Ahead.

7.8.3 WPGR Qualification

To be included in the calculation of total generating capacity within the McCamey Area, a WPGR owner must demonstrate, to ERCOT's satisfaction, that the WPGR will achieve at least a ten percent (10%) annual capacity factor. This determination may be made at ERCOT's discretion. After that demonstration has occurred, if the expected operation of a WPGR can reasonably be expected to operate at less than a ten percent (10%) annual capacity factor, then the WPGR owner shall notify ERCOT as soon as practical.

7.8.4 Determination of Tradable Generation Rights

(1) One Tradable Generation Right (TGR) provides a QSE scheduling WPGRs located in the McCamey Area the opportunity to schedule one (1) MW of McCamey Area WPGRs in its Resource Plan for each hour of the relevant period (peak or off-peak).

(2) ERCOT shall determine and allocate the on-peak and off-peak quantity of TGRs available to QSEs representing WPGRs located in the McCamey Area. The number of TGRs available must be based upon compliance with the ERCOT security criteria.

(3) ERCOT shall issue TGRs in on-peak and off-peak blocks as follows:

(a) The on-peak block is for the period from hour ending 0600 through the hour ending1800; and

(b) The off-peak block is for the period from hour ending1900 through the hour ending 0500.

7.8.5 *Allocation of Tradable Generation Rights*

ERCOT shall allocate the total amount of TGRs (expressed in MW) for each Operating Day to each QSE representing WPGRs in the McCamey Area based on the process as described in Section 7.8.8, ERCOT Day-Ahead and Real-Time Operations. For Wind-Powered Generation Resources, the capacity used for TGR allocation purposes is the capacity of the Wind-Powered Generation Resource established by the PUCT in its certification of the Generation Resource as either a REC generator or as a recipient of REC offsets, with the exception for new or recommissioned Generation Resources as described elsewhere in this Section 7.8, Congestion Management in McCamey Area. ERCOT shall post the results of the allocation of TGRs on the ERCOT website as soon as the allocation is available. The allocation posting must include: WPGR name, its QSE and MW of TGRs allocated by period, both on-peak and off-peak.

7.8.6 *Restriction on QSE Scheduling*

All QSEs scheduling WPGRs located within the McCamey Area are restricted in their Resource Plan submittals and Real Time operation by this Section 7.8, Congestion Management in McCamey Area. A QSE may designate generation levels for an Operating Hour in its Resource Plan from WPGRs located within the McCamey Area equal to the number of TGRs held by the QSE for that Operating Hour. A QSE may not designate generation levels for an Operating Hour in its Resource Plan from WPGRs located within the McCamey Area in excess of the number of TGRs held by the QSE for that Operating Hour.

7.8.7 *Accommodation of New or Recommissioned WPGRs*

In the case of a new or recommissioned WPGR located in the McCamey Area, the Resource must demonstrate to ERCOT's satisfaction that the anticipated capacity factor for the first month of commercial operation is greater than or equal to ten percent (10%) to be included in the determination of total generating capacity in the McCamey Area.

7.8.7.1 New or Recommissioned Unit Startup and Testing

For new or recommissioned Generation Resources in the McCamey Area that rely on phased-in Facility interconnection, the WPGR owner shall Supply ERCOT with a test plan. This plan must indicate how the Resource will increase capacity, along with the expected dates of such capacity becoming available. During the testing period before commercial operation, ERCOT shall allocate to the new WPGR, TGRs equal to the test plan capability if it is less than five (5) MW. ERCOT shall allocate to the new WPGR, TGRs proportional to the test plan's proportion of available capacity if it is more than five (5) MW.

7.8.7.2 New or Recommissioned Unit Commercial Operation

The owner of a WPGR coming online in the McCamey Area shall notify ERCOT three (3) Business Days before expected commercial operation. The Notice must include the MW of generation capacity expected to become commercial based on the PUCT certification of the Generation Resource as a REC generator, the date of expected commercial operation, and the scheduling QSE(s) with the associated capacity that the QSE will be scheduling from the WPGR. ERCOT shall allocate TGRs to the QSE(s) scheduling the WPGR as of the first day of expected commercial operation in accordance with the methods described in this Section 7.8.8. The owner of the WPGR is responsible for notifying ERCOT of any delays in expected commercial operation, as the calculation of the TGR allocation is partially contingent upon this information.

7.8.8 ERCOT Day Ahead and Real Time Operations

ERCOT's Day Ahead and Real Time operations allocate TGRs and manage McCamey Area Congestion as follows:

(1) ERCOT shall perform the Day Ahead calculation of the total amount of TGRs available as described above under the assumption that all of the WPGRs can respond to ERCOT Dispatch Instructions no more frequently than one instruction per three (3) consecutive hours (Initial TGRs).

(2) ERCOT shall post on its website the allocated TGRs for the Day Ahead

(3) ERCOT shall also perform a Day Ahead calculation of the total amount of TGRs available including the existence of RRWFs, as described in item (4) below (Actual TGRs). Rather than performing two separate Load flow analyses for each day, ERCOT may develop and apply a factor that reasonably represents the difference between the Initial TGRs and Actual TGRs.

(4) Any WPGR in the McCamey Area that cannot respond to ERCOT Dispatch Instructions in consecutive fifteen (15) minute intervals is designated as a Slow Response Wind Farm (SRWF). ERCOT shall allocate TGRs to SRWFs in proportion to their capacity-ratio-share among all McCamey Area WPGRs of the total available Initial TGRs. A SRWF may not generate at a level above its ownership of TGRs at any time.

(5) Any Generation Resource in the McCamey Area that can respond to ERCOT Dispatch Instructions in consecutive fifteen (15) minute intervals is called a Rapid Response Wind Farm (RRWF). ERCOT shall allocate TGRs to each RRWF in an amount equal to the RRWF's capacity ratio share among all McCamey Area WPGRs of the total available Initial TGRs, plus the capacity ratio share among all McCamey Area RRWFs of any positive difference between the available Actual TGRs and Initial TGRs. This sum of RRWF TGRs will be equal to the Day Ahead operating limits for RRWFs. A RRWF may generate at a level above its ownership of TGRs as allowed by system conditions and ERCOT Dispatch Instructions with the objective of maximizing the use of available transmission capacity.

(6) If, near Real Time, ERCOT determines that the Total Transmission Capacity in the McCamey Area is greater than the total amount of TGRs allocated to SRWFs and RRWFs, ERCOT may issue maximum output instructions (e.g., every fifteen (15) minutes or hour) to RRWFs that increase the allowed operating level to the maximum permitted by system conditions.

(7) If, near Real Time, ERCOT determines that the Total Transmission Capacity in the McCamey Area is less than the total amount of TGRs allocated to SRWFs and RRWFs, all RRWFs will be instructed to operate below their ownership of TGRs based on their pro-rata share of the transmission capacity shortfall. If RRWFs operate below their TGR ownership level for one hour, then each SRWF will be instructed by ERCOT to reduce output by ten (10) MWs (seventy (70) MW total) allowing each RRWF to increase its output until the total available transmission capacity is utilized. If permitted by system conditions, three (3) hours following the implementation of this procedure, ERCOT shall relax the constraints on each SRWF up to its TGR ownership if doing so will result in RRWFs being allowed to operate at or above their TGR ownership. Otherwise, ERCOT shall relax the SRWF constraints and shall issue instructions to RRWFs that will allow an operating level for all SRWFs and RRWFs that is equal on an installed (and available) capacity-ratio-share basis.

(8) ERCOT shall validate compliance with these rules at two (2) levels. First, ERCOT shall ensure that the amount of generation from WPGRs located in the McCamey Area in a QSE's Resource Plan does not exceed the amount of TGRs allocated to the QSE for that day. Second, if the amount of generation from a WPGR located in the McCamey area shown in a QSE's Resource Plan exceed its level of TGR ownership in Real Time, that WPGR is not entitled to be compensated for any amount of OOME Down Services provided in excess of the QSE's TGR ownership.

(9) ERCOT shall post on its website, as close to Real Time as possible, the flows and operating limits on the applicable transmission constraints in the McCamey Area and the aggregate amount of generation from WPGRs located in the McCamey Area.

(10) ERCOT shall develop a procedure for authenticating ownership for each TGR based on certification information provided by the PUCT (i.e., QSE, Resource owner, name of unit, date of commercial operation, output capacity).

7.8.9 *No Effect on Loads Acting as Resource*

These special provisions are designed to limit transmission Congestion costs in the McCamey Area and do not restrict Load acting as a Resource from supplying Ancillary Services in the ERCOT Ancillary Services markets.

7.9 Trading Hubs

The purpose of this section is to define each Trading Hub, list the transmission buses that are included in each Trading Hub, describe how to calculate the Trading Hub Price for each Trading Hub, and establish the duties of ERCOT and Market Participants related to transactions involving Trading Hubs.

7.9.1 *Definition of a Trading Hub*

(1) A Trading Hub is a specified group of Transmission Buses (60 kV and above) within the ERCOT System used for scheduling bilateral energy or capacity transactions between one or more Market Participants and/or ERCOT.

(2) All Trading Hubs are defined in Section 7.9.2, ERCOT Trading Hubs, and the only way to create other Trading Hubs is by amending Section 7.9.2 through the Protocol Revision Request process, as described in Section 21, Process for Protocol Revision.

(3) If a Transmission Bus that is included in a Trading Hub is physically removed from service, ERCOT shall file a Protocol Revision Request to revise the appropriate Trading Hub to reflect that event.

(4) Transactions involving a Trading Hub shall be expressed in a minimum of one (1) MW increments, unless specified otherwise in Section 7.9.3.4, Scheduling of Transactions Using ERCOT Trading Hubs.

7.9.2 *ERCOT Trading Hubs*

7.9.2.1 North 345 kV Trading Hub

(1) The North 345 kV Trading Hub is composed of the following Transmission Buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ANASW	345	2373	ANNA SS	345	NORTH
2	CN345	345	2372	COLLINSS	345	NORTH
3	WLSH	345	5925	DCEAST	345	NORTH
4	FMRVL	345	1685	FARM SW	345	NORTH
5	LPCCS	345	1684	LAMARPWR	345	NORTH
6	MNSES	345	1695	MOSES	345	NORTH
7	PRSSW	345	1692	PARIS SS	345	NORTH
8	SSPSW	345	1697	SULSP SS	345	NORTH
9	VLSES	345	1690	VALLEY	345	NORTH
10	ALNSW	345	2513	ALLEN1SS	345	NORTH
11	ALNSW	345	2514	ALLEN2SS	345	NORTH
12	ALLNC	345	1855	ALLIANCE	345	NORTH
13	BNDVS	345	970	BEN DV B	345	NORTH
14	BNBSW	345	1869	BENB A T	345	NORTH
15	BBSES	345	3380	BIGBRN	345	NORTH
16	BOSQUESW	345	246	BOSQUESW	345	NORTH
17	CDHSW	345	2420	C HILL	345	NORTH
18	CNTRY	345	1929	CENTURY1	345	NORTH
19	CNTRY	345	1930	CENTURY3	345	NORTH
20	CRLNW	345	2361	CLT NW	345	NORTH
21	CMNSW	345	1440	CMCHE SS	345	NORTH
22	CNRSW	345	2453	CNVIL	345	NORTH
23	CRTLD	345	1931	COURTLND	345	NORTH
24	DCSES	345	1888	DEC T	345	NORTH
25	EMSES	345	1859	EAGLE MT	345	NORTH
26	ELKTN	345	3105	ELKTON	345	NORTH
27	ELMOT	345	3406	ELM MOTT	345	NORTH
28	EVRSW	345	1882	EV WEST	345	NORTH
29	KWASS	345	11690	FANNIN	345	NORTH
30	FGRSW	345	3130	FOR GROV	345	NORTH
31	FORSW	345	2437	FORNEY	345	NORTH
32	FRNYPP	345	12410	FPLEFRB1	345	NORTH
33	FRNYPP	345	12420	FPLEFRB2	345	NORTH
34	GIBCRK	345	967	GIBCRK B	345	NORTH
35	HKBRY	345	2387	HACKBRY	345	NORTH
36	VLYRN	345	2389	IV VR	345	NORTH
37	JEWET	345	3391	JEWETT N	345	NORTH
38	JEWET	345	3390	JEWETT S	345	NORTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
39	KNEDL	345	1932	KENNDLE1	345	NORTH
40	KLNSW	345	3422	KILL SS	345	NORTH
41	LCSES	345	3409	LAKE CRK	345	NORTH
42	LIGSW	345	1916	LIG2 T	345	NORTH
43	LEG	345	46020	LIMEST 5	345	NORTH
44	LFKSW	345	3117	LUFKN SS	345	NORTH
45	LWSSW	345	646	LWSSWB	345	NORTH
46	MLSES	345	3100	MARTINLK	345	NORTH
47	MCCREE	345	833	MCCREE B	345	NORTH
48	MDANP	345	1939	MELP S	345	NORTH
49	MDANP	345	1936	MELP56NO	345	NORTH
50	ENTPR	345	3116	MT ENTRP	345	NORTH
51	NCDSE	345	3119	NACOG SE	345	NORTH
52	NORSW	345	2406	NORWD	345	NORTH
53	NUCOR	345	3396	NUCOR	345	NORTH
54	PKRSW	345	1436	PARKER	345	NORTH
55	KMCHI	345	11697	PITTSBRG	345	NORTH
56	PTENN	345	2522	PL TEN	345	NORTH
57	RENSW	345	2355	RENERTPL	345	NORTH
58	RCHBR	345	3133	RICHLND1	345	NORTH
59	RCHBR	345	3134	RICHLND2	345	NORTH
60	RNKSW	345	1853	ROANOKE	345	NORTH
61	RKCRK	345	1880	ROCKY CK	345	NORTH
62	RYSSW	345	2461	ROYSE S	345	NORTH
63	SGVSW	345	2433	SGVL SS	345	NORTH
64	SHBSW	345	3103	SHAMBRGR	345	NORTH
65	SHRSW	345	1918	SHERRY	345	NORTH
66	SHRTP	345	1917	SHERRY T	345	NORTH
67	SCSES	345	3109	STRYKER	345	NORTH
68	SYCRK	345	1935	SYCMR CK	345	NORTH
69	THSES	345	3405	T HOUSE	345	NORTH
70	TMPSW	345	3413	TEMPSSLT	345	NORTH
71	TNP_ONE	345	39950	TNP ONE	345	NORTH
72	TRCNR	345	2432	TRICORN	345	NORTH
73	TRSES	345	3123	TRINDAD1	345	NORTH
74	TRSES	345	3124	TRINDAD2	345	NORTH
75	TOKSW	345	3400	TWIN OAK	345	NORTH
76	VENSW	345	1907	VENUS N	345	NORTH
77	VENSW	345	1906	VENUS S	345	NORTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
78	WLVEE	345	2398	W LEVEE	345	NORTH
79	W_DENT	345	988	W.DENT B	345	NORTH
80	WTRML	345	2427	WATMILLW	345	NORTH
81	WCSWS	345	1434	WCPC	345	NORTH
82	WEBB	345	1911	WEBB 1	345	NORTH
83	WHTNY	345	240	WHITNEY	345	NORTH
84	WCPP	345	1421	WILLOWCK	345	NORTH

(2) The North 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.2 South 345 kV Trading Hub

(1) The South 345 kV Trading Hub is composed of the following Transmission Buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	AUSTRO	345	7040	AUSTRO34	345	SOUTH
2	BLESSING	345	8123	BLESSNG6	345	SOUTH
3	CAGNON	345	5056	CAGNON	345	SOUTH
4	COLETO	345	8164	COLETO 6	345	SOUTH
5	CLEASP	345	7050	CRLSPG34	345	SOUTH
6	NEDIN	345	8383	EDNBRG 6	345	SOUTH
7	FAYETT	345	7057	FAYETT34	345	SOUTH
8	FPPYD1	345	7056	FPPYD134	345	SOUTH
9	FPPYD2	345	7055	FPPYD234	345	SOUTH
10	GARFIE	345	7048	GARFIE34	345	SOUTH
11	GUADG	345	7047	GPP	345	SOUTH
12	HAYSEN	345	7043	HAYSN 34	345	SOUTH
13	HILLCTRY	345	5211	HILL CTY	345	SOUTH
14	HOLMAN	345	9073	HOLMAN	345	SOUTH
15	KENDAL	345	7046	KENDAL34	345	SOUTH
16	LA_PALMA	345	8317	LAPALM 6	345	SOUTH
17	LON_HILL	345	8455	LNHILL 6	345	SOUTH
18	LOSTPI	345	7041	LOSTPN34	345	SOUTH
19	LYTTON_S	345	9074	LYTTON	345	SOUTH
20	MARION	345	7044	MARION34	345	SOUTH
21	PAWNEE	345	5725	PAWNESW6	345	SOUTH

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
22	RIOHONDO	345	8318	RIOHND 6	345	SOUTH

23	RIONOG	345	7051	RIONO 34	345	SOUTH
24	SALEM	345	7058	SALEM 34	345	SOUTH
25	SDSES	345	3429	SANDOW	345	SOUTH
26	SANMIGL	345	52	SANMIGEL	345	SOUTH
27	SKYLINE	345	5371	SKYLINE	345	SOUTH
28	STP	345	5915	SO TEX 5	345	SOUTH
29	CALAVERS	345	5400	SPRUCE	345	SOUTH
30	BRAUNIG	345	5475	VON ROSE	345	SOUTH
31	WHITEPT	345	8956	WHITEPT	345	SOUTH
32	ZORN	345	7042	ZORN 34	345	SOUTH
33	ZORN	345	7045	ZORN 34	345	SOUTH

(2) The South 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.3 Houston 345 kV Trading Hub

(1) The Houston 345 kV Trading Hub is composed of the following listed transmission buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ADK	345	45600	ADICKS 5	345	HOUSTON
2	_BI	345	47000	BELAIR 5	345	HOUSTON
3	CBY	345	40000	CEDARP 5	345	HOUSTON
4	CTR	345	40240	CENTER	345	HOUSTON
5	CHB	345	40255	CHAMBR 5	345	HOUSTON
6	DPW	345	40450	DEPWTR 5	345	HOUSTON
7	DOW	345	42500	DOW345 5	345	HOUSTON
8	RNS	345	40600	FRONTR	345	HOUSTON
9	GBY	345	40700	GRNBYU 5	345	HOUSTON
10	_JN	345	47300	JENETA 5	345	HOUSTON
11	_KG	345	40900	KING 5	345	HOUSTON
12	KDL	345	45972	KUYDAL 5	345	HOUSTON
13	_NB	345	46100	N_BELT 5	345	HOUSTON
14	_OB	345	44500	OBRIEN 5	345	HOUSTON
15	PHR	345	42000	P_H_R_5	345	HOUSTON
16	SDN	345	41430	SHELDN 5	345	HOUSTON
17	SMITHERS	345	44650	SMTHRS 5	345	HOUSTON
18	THW	345	45500	T_H_W_5	345	HOUSTON
19	WAP	345	44000	W_A_P_5	345	HOUSTON
20	_WO	345	46600	WHITOK 5	345	HOUSTON

(2) The Houston 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.4 West 345 kV Trading Hub

(1) The West 345 kV Trading Hub is composed of the following listed transmission buses:

	ERCOT Operations		Steady State Working Group			
No.	Station Mnemonic	kV	Bus Number	Name	kV	Trading Hub
1	ABMB	345	6230	ABMULCE7	345	WEST
2	BOMSW	345	1422	BOWMAN	345	WEST
3	OECCS	345	1020	EHV TIET	345	WEST
4	BTRCK	345	1050	ENRONIPP	345	WEST
5	FSHSW	345	1425	FISHRDSS	345	WEST
6	FLCNS	345	1025	FS COGEN	345	WEST
7	GRSES	345	1430	GRAHAM	345	WEST
8	JCKSW	345	1429	JXBRO SS	345	WEST
9	MDLNE	345	1021	MIDL E T	345	WEST
10	MOSSW	345	1018	MOSS	345	WEST
11	MGSES	345	1030	MRGN CRK	345	WEST
12	DCTM	345	6096	NORTHDC7	345	WEST
13	ODEHV	345	1026	ODES EHV	345	WEST
14	OKLA	345	6100	OKLAEHV7	345	WEST
15	SARC	345	6444	SAREDCK7	345	WEST
16	SWCOG	345	1420	SWEETWTR	345	WEST
17	TWINBUTE	345	6009	TWBT7	345	WEST

(2) The West 345 kV Trading Hub Price is the simple average of the bus prices in each interval for each bus included in this Trading Hub.

7.9.2.5 ERCOT Hub Average 345 kV Trading Hub

The ERCOT Hub Average 345 kV Trading Hub Price is the simple average of the North 345 kV Trading Hub Price, South 345 kV Trading Hub Price, Houston 345 kV Trading Hub Price, and West 345 kV Trading Hub Price.

7.9.2.6 ERCOT Bus Average 345 kV Trading Hub

(1) The ERCOT Bus Average 345 kV Trading Hub is composed of the buses listed in Section 7.9.2.1, the North 345 kV Trading Hub, Section 7.9.2.2, the South 345 kV Trading Hub, Section 7.9.2.3, the Houston 345 kV Trading Hub and Section 7.9.2.4, the West 345 kV Trading Hub.

(2) Until superseded by implementation of a different market design for the ERCOT market (e.g., a nodal market design), the ERCOT Bus Average 345 kV Trading Hub Price for each interval shall approximately consist of a 56% weighting applied to the North 345 kV Trading Hub price, a 21% weighting applied to the South 345 kV Trading Hub price, a 12% weighting applied to the Houston 345 kV Trading Hub price, and a 10% weighting

applied to the West 345 kV Trading Hub price. For the exact weights, please refer to Section 7.9.3.4, Scheduling of Transactions Using ERCOT Trading Hubs.

7.9.3 ERCOT Responsibilities

7.9.3.1 Posting of a List of Buses included in Trading Hubs

(1) ERCOT shall post a list of all the buses included in each ERCOT Trading Hub on the public MIS. The list must include the bus name and kV rating as used by ERCOT Operations, the bus number, bus name and kV rating as used in the Steady State Working Group (SSWG) base cases, and the Congestion Zone that the bus is assigned to.

(2) ERCOT shall update the list of buses included in each ERCOT Trading Hub as soon as possible whenever a new Trading Hub is created under this Section 7.9 or when affected Transmission Buses are renamed in either the ERCOT Operations model or the SSWG model.

7.9.3.2 Calculation of Trading Hub Prices

ERCOT shall calculate Trading Hub Prices for each Settlement Interval. The bus price for each Transmission Bus for each Settlement Interval is the Market Clearing Price at that bus as determined elsewhere in these Protocols for that Settlement Interval.

7.9.3.3 Posting of Trading Hub Prices

ERCOT shall post the Trading Hub Prices for each ERCOT Trading Hub for each Settlement Interval as soon as practicable on the public MIS.

7.9.3.4 Scheduling of Transactions Using ERCOT Trading Hubs

(1) Until ERCOT's scheduling system is updated to automatically convert transactions involving Trading Hubs into transactions involving Congestion Zones, QSEs having any transaction involving an ERCOT Trading Hub shall convert each such transaction to one that can be expressed as a scheduled transaction between existing Congestion Zones.

(2) Market Participants shall use the following matrix to convert transactions at Trading Hubs to existing Congestion Zones:

	2007 Congestion Zone			
Trading Hub	North	South	Houston	West
North	1.000			
South		1.000		
Houston	0.050		0.950	
West	0.059			0.941
Bus Average	0.559	0.214	0.123	0.104
ERCOT Average	0.277	0.250	0.238	0.235

ERCOT

EXHIBIT 3

Date: September 9, 2008
To: Board of Directors
From: Mark Dreyfus, Technical Advisory Committee (TAC) Chair
Subject: 2009 Commercially Significant Constraints (CSCs) and Congestion Zones

Issue for the ERCOT Board of Directors

ERCOT Board of Director Meeting Date: September 16, 2008
Agenda Item No.: 10d

Issue:
Designation of 2009 CSCs in the ERCOT transmission system and Transmission Congestion Zones.

Background/History:
Protocol Section 7.2.1, Process for Determining CSCs, states "CSCs and resulting Congestion Zones will be reassessed annually by November 1 of each year." Board approval is required for the annual CSC and Congestion Zone designations.

The Congestion Management Working Group (CMWG), under the auspices of the Wholesale Market Subcommittee (WMS) and TAC, has been working on this issue. ERCOT Staff provided the underlying analysis using the transmission topology for 2009 and the resulting load flow data to determine expected operating limits, candidate CSCs and associated constraints to be used in the designation of CSCs for 2009. The CMWG did not reach a unanimous recommendation for the 2009 CSCs and Congestion Zones and brought the following three proposals to the August 20, 2008 WMS for consideration.

Scenario 3b (ERCOT Staff Proposal):

- Four Congestion Zones: West, North, South and Houston
- Commercially Significant Constraints:
  - CSC#1 – North to Houston* – Singleton to Obrien; Singleton to TH Wharton 345-kV double circuit
  - CSC#2 – North to South – Lake Creek to Temple; Tradinghouse to Temple Pecan Creek 345-kV double circuit
  - CSC#3 South to North – Temple to Lake Creek; Temple Pecan Creek to Tradinghouse 345-kV double circuit
  - CSC#4 – West to North – Graham to Benbrook; Graham to Parker 345-kV double circuit
  - CSC#5 – North to West –Benbrook to Graham; Parker to Graham 345-kV double circuit

  **For CSC#1 - North o Houston – Singleton is not scheduled to be in-service until May 2009.*

Scenario 3g:

- Same as ERCOT's proposal except for CSC#4 and CSC#5:
  - CSC#4 – West to North –Graham to Long Creek; Graham to Cook Field Road 345-kV double circuit
  - CSC#5 – North to West –Long Creek to Graham; Cook Field Road to Graham 345-kV double circuit

Scenario 3h:

- Same as ERCOT's proposal except for CSC#4 and CSC#5:
  - CSC#4 – West to North – Sweetwater to Long Creek; Abilene Mulberry Creek to Long Creek 345-kV double circuit
  - CSC#5 – North to West –Long Creek to Sweetwater; Long Creek to Abilene Mulberry Creek 345-kV double circuit

At the August 20, 2008 WMS meeting, a motion to endorse the ERCOT Staff proposal, Scenario 3b, failed by roll call vote with 43.2% in favor, 56.8% opposed and two abstentions. There were twelve opposing votes from the Cooperative (1), Municipal (1), Investor Owned Utility (IOU) (3), Consumer (1), Independent Retail Electric Provider (IREP) (4), and Independent Power Marketer (IPM) (2) Market Segments and two abstentions from the IOU (1) and Consumer (1) Market Segments. A subsequent motion to endorse Scenario 3g failed to receive a second. A third motion to recommend the Scenario 3h proposal to TAC passed by WMS roll call vote with 61.1% in favor, 38.9% opposed and two abstentions. There were ten opposing votes from the Cooperative (1), Municipal (2), IOU (1), Independent Generator (4) and IPM (2) Market Segments and two abstentions from the Cooperative and Municipal Market Segments.

At the September 4, 2008 TAC meeting, the TAC heard the proposals presented to WMS as well as a fourth proposal, Scenario 3i, which is described below.

Scenario 3i:

- Same as Scenario 3h except for the cluster analysis performed. In Scenario 3i, Olkaunion remains in the West Congestion management zone instead of moving to the North Congestion management zone as is the case in Scenario 3h.

Comparison of Scenarios:

CSC Analysis – MWs of Load Moving Zones by Scenario

	Scenario 3b	Scenario 3g	Scenario 3h	Scenario 3i
North to South	1137.39	1156.40	1150.38	1150.38
South to Houston	107.54	53.41	53.41	53.41
West to North	4.97	762.08	762.08	761.63
West to South	3.80	3.80	3.80	3.80
North to West	7.63	0	0	0
Total	1261.33	1975.69	1988.57	1969.22

ERCOT

CSC Analysis – MWs of Generation Moving Zones by Scenario

	Scenario 3b	Scenario 3g	Scenario 3h	Scenario 3i
North to South	0	0	0	0
South to Houston	0	0	0	0
West to North	0	832	2117.67	1468
West to South	0	0	0	0
North to West	0	0	0	0
Total	0	832	2117.67	1468

Attachment A also includes a diagram of selected 345-kV lines that are different among the proposed scenarios.

After discussing the four proposals for the 2009 CSCs as described above, a motion to recommend the Scenario 3i proposal passed by TAC roll call vote with five opposing votes from the IOU (1), Independent Generator (2) and Consumer (2) Market Segments and four abstentions from the Municipal (1), Independent Generator (1), Consumer (1) and IPM (1) Market Segments.

Key Factors Influencing Issue:
The TAC met and discussed four proposals for the 2009 CSCs and recommends Board approval of the Scenario 3i proposal for the 2009 Congestion Zones and CSCs.

2009 CSCs:

- CSC#1 – North to Houston* – Singleton to Obrien; Singleton to TH Wharton 345-kV double circuit
- CSC#2 – North to South – Lake Creek to Temple; Tradinghouse to Temple Pecan Creek 345-kV double circuit
- CSC#3 South to North – Temple to Lake Creek; Temple Pecan Creek to Tradinghouse 345-kV double circuit
- CSC#4– West to North** – Sweetwater to Long Creek; Abilene Mulberry Creek to Long Creek 345-kV double circuit
- CSC#5 – North to West** – Long Creek to Sweetwater; Long Creek to Abilene Mulberry Creek 345-kV double circuit

**For CSC#1 - North o Houston – Singleton is not scheduled to be in-service until May 2009.*

***Clustered using post-contingency (Oklaunion to Fisher Road; Fisher Road to Bowman 345-kV shift factors)*

2009 Congestion Zones: 1 – West 2009 2 – North 2009 3 – Houston 2009 4 – South 2009 Attachment B includes a diagram of the 2009 CSCs as recommended by TAC.
<u>Alternatives</u>: 1. Approve the TAC recommendation regarding CSCs and Congestion Zones for 2009; 2. reject the TAC recommendation; or 3. remand to TAC with instructions.
<u>Conclusion/Recommendation</u>: TAC recommends that the Board approve the Scenario 3i proposal for 2009 CSCs and Congestion Zones.

ERCOT

EXHIBIT 4

Date: October 10, 2008
To: Board of Directors
From: Mark Dreyfus, TAC Chair
Subject: 2009 CSCs, Congestion Zones, CREs and Boundary Generation Resources

Issue for the ERCOT Board of Directors

ERCOT Board of Director Meeting Date: October 21, 2008
Agenda Item No.: 7e

Issue:

Designation of 2009 Commercially Significant Constraints (CSCs), Transmission Congestion Zones, Closely Related Elements (CREs) and Boundary Generation Resources in the ERCOT transmission system.

Background/History:

At the September 16, 2008 ERCOT Board of Director's (Board) Meeting, the Board remanded consideration of the 2009 CSCs to the Technical Advisory Committee (TAC). The Board instructed the TAC, working with ERCOT Staff, to re-examine Options 3b, 3h and 3i (as described in Attachment A) and to return to the October Board with a single recommendation for CSCs and the resulting CREs so that the Board could comply with Protocol Section 7.2, CSC Zone Determination Process, which states the following:

> By November 1 of each year, the appropriate ERCOT subcommittee will report to the TAC and ERCOT Board with recommended CSC designations, resulting Congestion Zone boundaries with any granted exemptions noted, CRE designations and associated Boundary Generation Resources for ERCOT Board review and approval.

ERCOT Staff provided stakeholders with additional analysis as well as identified potential CREs for each of the three options (3b, 3h, and 3i) using at a minimum the process prescribed in items (1) – (6) of Protocol Section 7.2.3, Determining Closely Related Elements (CREs). The proposed CREs for Options 3b, 3h and 3i are included in Attachment C. The proposed boundary generation Resources for each option are included in Attachment D.

On October 8, 2008, the TAC and the Wholesale Market Subcommittee (WMS) held a joint meeting to re-examine Options 3b, 3h and 3i to make a recommendation to the Board for the designation of the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system. After discussing the various options, the following motions were voted upon:

- A WMS motion to eliminate consideration of Option 3b passed with 75.6% in favor, 24.4% opposed and two abstentions from the Generator Market Segment. Opposing votes were recorded in the Cooperative, Generator (2), and Independent Power Marketer

(IPM) (2) Market Segments.

- A WMS motion to recommend approval of Option 3i for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system passed with 82.5% in favor, 17.5% opposed and six abstentions. Opposing votes were recorded in the Investor Owned Utility (IOU) and Generator Market Segments. The six abstentions were recorded in the Municipal, Generator (3), Consumer and IPM Market Segments.
- A TAC motion to recommend approval of Option 3h for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system failed with two in favor, 23 opposed and five abstentions. Opposing votes were recorded in the Cooperative (4), Municipal (4), IOU (3), Generator (2), Consumer (5), Independent Retail Electric Provider (IREP) (3) and IPM (2) Market Segments. The five abstentions were recorded in the Generator (2), Consumer, IREP and IPM Market Segments.
- A TAC motion to recommend approval of Option 3i for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system passed with 22 in favor, six opposed and two abstentions. Opposing votes were recorded in the IOU, Generator (2), Consumer (2), and IPM Market Segments. The two abstentions were recorded in the Generator and Consumer Market Segments.

Key Factors Influencing Issue:

The WMS and TAC met, discussed and recommend Board approval of the Option 3i proposal for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system.

2009 CSCs:

- CSC#1 – West to North – Sweetwater to Long Creek; Abilene Mulberry Creek to Long Creek 345-kV double circuit
- CSC#2 – North to South – Lake Creek to Temple; Tradinghouse to Temple Pecan Creek 345-kV double circuit
- CSC#3 South to North – Temple to Lake Creek; Temple Pecan Creek to Tradinghouse 345-kV double circuit
- CSC#4– North to Houston* – Singleton to Obrien; Singleton to TH Wharton 345-kV double circuit
- CSC#5 – North to West – Long Creek to Sweetwater; Long Creek to Abilene Mulberry Creek 345-kV double circuit

**For CSC#4 - North to Houston – Singleton is not scheduled to be in-service until May 2009.*

ERCOT

2009 Congestion Zones:

1 – West 2009
2 – North 2009
3 – Houston 2009
4 – South 2009

Please refer to the complete bus to zone assignments for Option 3i included in Attachment B.

Zone assignments under Option 3i are the result of clustering using post-contingency (Oklaunion to Fisher Road; Fisher Road to Bowman 345-kV) shift factors.

2009 CREs:

Please refer to CREs for Option 3i listed in Attachment B.

2009 Boundary Generation Resources:

West to North and North to West CSCs

- Mesquite Wind Farms
- Cook Field Wind
- Wichita Falls
- Oklaunion

North to South and South to North CSCs

- Lake Creek
- Sandow

Attachment E includes a diagram of the 2009 CSCs as recommended by TAC.

Alternatives:

(1) Approve the TAC recommendation regarding 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system;
(2) reject the TAC recommendation; or
(3) remand to TAC with instructions.

Conclusion/Recommendation:

TAC recommends that the Board approve the Option 3i proposal for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system.

ERCOT

ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.
BOARD OF DIRECTORS RESOLUTION

WHEREAS, the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) deems it desirable and in ERCOT's best interest to approve the Option 3i proposal as described in Attachment A for the 2009 CSCs, Transmission Congestion Zones, CREs and Boundary Generation Resources in the ERCOT transmission system.

NOW, THEREFORE, BE IT RESOLVED, that the ERCOT Board hereby approves Option 3i described in Attachment A for the 2009 CSCs, Transmission Congestion Zones, CREs and Boundary Generation Resources in the ERCOT transmission system.

CORPORATE SECRETARY'S CERTIFICATE

I, Michael G. Grable, Corporate Secretary of ERCOT, do hereby certify that, at its October 21, 2008 meeting, the ERCOT Board of Directors passed a motion approving the above Resolution by a vote of ____________________________________.

IN WITNESS WHEREOF, I have hereunto set my hand this _______day of ___________, 2008.

____
Michael G. Grable
Corporate Secretary

APPEAL OF TAC DECISION REGARDING 2009 CSC RECOMMENDATION

Submitter's Information	
Name	C. Richard Ross
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Phone Number	918-599-2966
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Market Segment	Investor Owned Utility

Appeal of TAC Decision Regarding 2009 CSC Recommendation

American Electric Power respectfully appeals the decision of the ERCOT Technical Advisory Committee ("TAC) made at its October 8, 2008 meeting to recommend the Commercially Significant Constraints (CSCs), Zonal Clustering Closely Related Elements (CREs) and Boundary Units associated with Scenario 3i. It is AEP's belief, for the reasons that follow, that the ERCOT Board should instead approve the CSCs, Zonal Clustering, CREs and Boundary Units associated with Scenario 3h.

The ERCOT Protocols Section 7.2, CSC Zone Determination Process, provides the general outline of the process to be utilized to determine the Congestion Zones each year. This outlines the selection of CSCs, performance of clustering analysis and the identification of CREs and Boundary Units. However, much of the specific detailed procedures have been developed through the historical actions taken each year since the implementation of the ERCOT administered markets. Historically, these procedures appear to have been applied on a consistent and non-discriminatory basis.

The historically accepted process first requires the selection of the appropriate CSCs. Next in the process comes the clustering of generators and loads that have similar impacts on those constraints. As relevant to this appeal, there is agreement concerning the proper 2009 CSC's, since both Scenarios are based on identical CSC selections.

Concern arose, however, in connection with the second step in the process. Using the historically accepted clustering process, a significant amount of generation currently in the West 2008 Congestion Zone would be placed in what would become the North 2009 Congestion Zone. Although the proper procedures were followed – in fact precisely the same procedure that have always been used in connection with the clustering process - and no reliability issues were identified, some parties became alarmed by the significant movement of certain generation into the North Zone. As a result, these parties immediately sought out ways to overturn the decision or somehow reduce this shift in generation. The result of those efforts was the creation of Scenario 3i through the addition of unprecedented and inconsistently applied assumptions which uniquely and adversely impacts one single generating unit (Oklaunion) .

The critical ERCOT 3i assumptions are unprecedented and appear to be end result oriented. Specifically, the assumption that certain segments of the ERCOT transmission system affecting only one CSC were out of service, is itself unprecedented; and, piling one unprecedented assumption upon another – ERCOT assumes that Oklaunion- - a low cost base load coal fired unit - is likely to vary its output. Through the course of this year's analysis, other erroneous assumptions in use by ERCOT specifically regarding the Oklaunion plant also came to light. It is AEP's belief that all these unique assumptions are both inconsistent with the ERCOT Protocols and may be inconsistent with ERCOT's requirement to provide nondiscriminatory access to the ERCOT transmission system.

(1) ERCOT Protocol 7.2.1 requires: "... ERCOT staff will complete an analysis of Load flow data using the latest Steady State Working Group Data Set A summer peak case and will determine expected operating limits, candidate CSCs and associated constraints to be used in the designation of CSCs for the upcoming calendar year." This model includes the line segment from Oklaunion to Fisher Road and from Fisher Road to Bowman. ERCOT's actions to remove only this line segment for the purposes of performing the 3i cluster analysis, creates three problems:

a. This results in a significant a departure from historical practices since all prior years' analysis were based upon a fully intact ERCOT transmission system for all CSCs. This would have included the Oklaunion to Bowman line segment being operational/in service.

b. ERCOT and others justify this unprecedented post contingency analysis by explaining it is part of the real time post contingency operation of the ERCOT grid. While this may be true, post contingency analysis also is applied to every other CSC interface and element of the transmission grid in ERCOT's real time operations. Exclusively applying this standard to the West interface causes generators and loads which impact that CSC to be treated in a manner differently than those generators and loads impacting other CSCs. Such different treatment, most severely impacted the Oklaunion plant. Under these alternate procedures the Oklaunion plant is clustered into the West 2009 zone instead of being properly clustered in the North 2009 zone. This treatment robs the Oklaunion plant of its proper access to make deliveries in the North 2009 congestion zone. In taking these steps, these actions amount to a violation of Protocol 1.2 (1) which call upon ERCOT to "Ensure access to the transmission and distribution systems for all buyers and sellers of electricity on ***nondiscriminatory*** terms.(emphasis added)"

APPEAL OF TAC DECISION REGARDING 2009 CSC RECOMMENDATION

c. The mere action of removing the Oklaunion to Bowman lines from the case is a modification of the case. One simply can not take the "Steady State Working Group Data Set A summer peak case," remove any element from service , much less a major 345 KV line, and still call it the "Steady State Working Group Data Set A summer peak case." Such a modified case is clearly not the case called for under the Protocols and, as a result, its use as the basis for the clustering analysis is in conflict with the requirements of the Protocols.

(2) ERCOT Protocol 7.2.4, Determining Generation Resources Deemed Likely to Vary Their Output, requires ERCOT each year to define a list of resources "fueled by nuclear fuel, coal or lignite." Since the Oklaunion plant is fueled by coal, in accordance with this section of the protocols it is excluded from the list of units likely to vary their output. These units like Oklaunion, commonly referred to unmovable, are then excluded from the Zonal Shift factor calculations for the reset of the year. In each prior year this status has also been utilized as ERCOT performs its analysis to determine Closely Related Elements (CREs). This year, in contrast, ERCOT decided to treat the Oklaunion station as movable for the purposes of the CRE selection process. It is unclear how this assumption impacted the remaining steps of the CRE selection process, but two things are clear:

a. The Oklaunion plant was treated differently than any other coal fired unit has been treated in the past (including its own treatment in prior years).

b. This treatment was applied exclusively to the Oklaunion plant and such discriminatory treatment is a violation of ERCOT Protocol 1.2 stating "In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, ***nondiscriminatory*** manner. (emphasis added)" During the TAC/WMS Technical Review WebEx on October 6, 2008, the ERCOT staff justified this treatment as reasonable by explaining that (i) technically the Protocols do not state how they have to conduct the CRE analysis and (ii) there is "pretty good evidence that it does move in response to price." AEP does not argue with ERCOT's reasonable consideration of a generating unit's actual behavior in the CRE analysis. However, AEP does take issue with the discriminatory way in which it was applied exclusively to the Oklaunion station. There is "pretty good evidence" that most, if not all, of the coal fired units in the ERCOT region move in response to price. If ERCOT is to make such reasonable assumptions, they must be implemented on a nondiscriminatory basis. In this case all coal fired units should have been treated as movable for the purposes of the remaining CRE analysis and to do differently creates a conflict with Protocols Section 1.2.

(3) The issue or concern over stability limits has also been raised from time to time during the debate over the West Zone CSCs. From discussions that have taken

place in the Congestion Management Working Group, several conclusions are apparent:

a. The modeling of the stability limits has been flawed for quite some time and may have resulted in stability limits that were below what was necessary. During the very few instances where this stability limit was the binding constraints, this would have resulted in the unnecessary reduction in exports from the West zone, since the system was being operated at levels that were below its capabilities ("phantom congestion").

b. This error was in part due to incorrect assumptions regarding the Power System Stabilizer ("PSS") in use at the Oklaunion plant. ERCOT's modeling assumed the Oklaunion PSS was not operational and therefore assumed Oklaunion contributed to the small signal instability in the region. The Oklaunion PSS is in fact operational, as is required by Protocol 6.5.7.2 (4). As a result, any contribution the Oklaunion plant would have to the stability issues is mitigated by the operation of its PSS. Any use of ERCOT's small signal stability issues as a justification for moving Oklaunion into the West zone would effectively and unreasonably require Oklaunion to resolve problems created by other resources not having operational PSSs.

c. Given the errors in assumptions, changes in system topology and CSCs it is clear that a comprehensive review of ERCOT's small signal instability limits is necessary. While the broad arc/interface in prior years has loosely correlated to the west zone, this may no longer be the proper interface/measuring point for the stability limit and is of little use as guidance when comparing Scenario 3i and 3h.

In addition to the problems addressed above, concerns have been raised that Scenario 3h will somehow lead to greater costs. In response to these concerns AEP suggests:

(1) ERCOT has indicated, and AEP agrees, that the interaction of the many different ERCOT functions/activities make it almost impossible to determine the total net impact of any of the scenarios considered.

(2) Placing the Oklaunion plant in the North 2009 zone will not lead to higher uplift and costs for the following reasons:

a. ERCOT staff confirmed at the TAC meeting on October 8, 2008 that under Scenario 3h there will be sufficient generation, even without Oklaunion, to relieve any West to North congestion. As a result, any West to North congestion will be capable of being relieved by reducing output from units in the West and will not require any OOME instructions to the Oklaunion plant.

b. AEP has indicated that it is its intent to fully schedule its shares of the output of the Oklaunion plant. When placed in the North 2009 zone, it is likely the unit will be running at or very near its scheduled output at all times. In the event ERCOT does find it necessary to issue OOME instructions to the plant as a result of its being identified as a Boundary Unit, such instructions to operate at scheduled levels will result in little or no additional compensation.

c. As explained earlier, no specific instructions for Oklaunion plant related to stability limits should be necessary. The remaining units in the West zone should be capable of resolving any actual stability limit problems that exist. In the unlikely event that changes in the operation of units outside the West zone are necessary, other units are also capable of providing similar relief and this relief should not be applied to Oklaunion plant alone.

A transparent and equitable application of the rules and procedures protects a competitive market by assuring all market participants, large and small, of a fair opportunity to compete in the market. AEP respectfully submits that these selective departures from established procedures are inconsistent with principles of market fairness. AEP has no objection to revisiting the CSC Zone Determination procedures, but submits that it should be a comprehensive review conducted when time permits, in connection with analysis performed for calendar year 2010. Therefore, AEP respectfully requests that the ERCOT Board reject TAC's recommendation of Scenario 3i in favor of Scenario 3h.

EXHIBIT 6

ERCOT

2009 CSC Study

Proposals

Version 3.3

Document Revisions

Date	Version	Description	Author(s)
07/02/2008	1.0	First draft	Jeff Billo
07/09/2008	1.1	Draft – added scenario 4	Jeff Billo
07/09/2008	1.2	Draft – added 2008 congestion data and minor edits	Isabel Flores
07/10/2008	1.3	Add scenario 5 and congestion costs	Isabel Flores
07/16/2008	2.0	Add scenarios 3a, 3b, 3c, 3d, 3e	Jeff Billo
07/21/2008	2.1	Add scenarios 3f, 6a, 6b, 6c	Jeff Billo
07/24/2008	3.0	Add scenario 3g	Jeff Billo
08/01/2008	3.1	Revised to show only the 3 options being submitted to WMS for consideration.	Isabel Flores
08/13/2008	3.2	Added scenario 3h and at the request of Market Participants' only scenarios 3b, 3g, and 3h are shown in this document version..	Isabel Flores
09/03/2008	3.3	Added scenario 3i and updated tables.	Isabel Flores

Table of Contents

2009 CSC Determination Study

1. Background

Protocol Section 7.2.1 requires ERCOT Staff to conduct an annual analysis to determine the upcoming year's Commercially Significant Constraints (CSCs). This analysis may include a transfer study, an evaluation of past congestion costs, and a projection of congestion costs for the upcoming year; ERCOT's analysis includes all of these features.

2. 2009 Significant Changes to the ERCOT grid

Per the May 2008 TPIT, these are the significant transmission projects scheduled to go in-service by the end of 2009:

1. Jack Creek 345/138-kV substation and associated projects (Sept. 2008)
2. Brownwood-Goldthwaite 138-kV line reconductor (Dec. 2008)
3. Singleton Switch (May 2009)
4. Waller-Prairie View-Seaway-Macedonia 138-kV line upgrade (Sept. 2009)
5. West Levee-Norwood 345-kV line (Dec. 2009)
6. Leon-Flat Creek 138-kV line upgrade (Dec. 2009)

Generation projects scheduled to go in-service by the end of 2009:

1. Victoria Power Station (July 2008)
2. Bosque Expansion (Mar. 2009)
3. Dansby 3 (Apr. 2009)
4. VH Braunig Peakers (May 2009)
5. Oak Grove 1 (July 2009)
6. Sandow 5 (July 2009)
7. Winchester (July 2009)
8. Sandhill Peakers (Nov. 2009)
9. 7981 MW (total) of west Texas wind, 173 MW of north Texas wind, and 590 MW of south Texas wind scheduled to be in-service by the end of 2008
10. 8206 MW of west Texas wind, 173 MW of north Texas wind, and 688 MW of south Texas wind scheduled to be in-service by September 2009

3. Transfer Study

The Steady State Working Group (SSWG) 2009 Data Set A 2009 summer peak base case was used for the transfer analysis. A congestion management (CM) zone to CM zone transfer analysis was performed by mapping all generators to their respective 2008 CM zones. New generation units were mapped to their assumed CM zone.

Transfer analysis was performed for the following zone to zone generation transfers:

1. West to North
2. South to North
3. North to South
4. North to Houston
5. North to West

The Singleton Switch Station was included in the base case because it is scheduled to be in-service by May 2009. However, since it will not be in-service for all of 2009 a second transfer analysis was performed. The base case was modified by removing the Singleton Switch Station and replacing the connected branches with the existing branch data for the Jewett-Tomball, Jewett-TH Wharton, Gibbons Creek-Roans Prairie, and Gibbons Creek-Obrien 345-kV lines. The North to Houston transfer study was rerun on the modified base case.

The results of the transfer studies are presented in the attached spreadsheet:

2009_CSC_Transfer_Analysis.xls

4. Evaluation of Current Congestion Events

Table 1 is an estimate of zonal congestion costs for the period January through May; costs were assigned to contingency and overloaded elements based on those identified when determining CSC limits:

CSC	Contingency	Overloaded Element	Costs	% of total
N_H	DCKT Jewett - TH Wharton & Tomball 345kV	Watson Chapel - Robertson 138kV	$59,822,113.66	66.52%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV DCKT Temple Switch – Lake Creek & Temple Pecan Creek 345 kV	Watson Chapel - Robertson 138kV Temple Pecan Creek – Temple 138kV	$30,914,645.57	42.48%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Lorena - Waco West 69 kV	$6,175,256.24	8.49%
N_S	DCKT Temple Pecan Creek - Tradinghouse & Temple Switch - Lake Creek 345kV	Watson Chapel - Robertson 138kV	$3,497,318.90	4.81%
N_S	DCKT Temple Switch - Lake Creek & Temple Pecan Creek 345 kV	Temple Pecan Creek - Temple 138kV	$ 2,999,633.29	4.12%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Waco - Waco West 69kV	$1,615,205.93	2.22%
N_S	DCKT Temple Pecan Creek - Tradinghouse & Temple Switch - Lake Creek 345kV	Waco West - Waco Woodway 138kV	$1,415,734.42	1.95%

CSC	Contingency	Overloaded Element	Costs	% of total
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Temple Creek - Temple Switch 138kV	$932,185.42	1.28%
N_S	DCKT Sandow - Temple 345 kV	Killeen Clark Road – Copperas Cove 138kV	$932,185.42	1.28%
N_S	DCKT Austrop - Sandow SW 345kV	Sandow SW - Salty 138kV	$90,688.89	0.12%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Waco Woodway - Waco West 138kV	$ 63,462.48	0.09%
N_W	SCKT San Angelo Red Creek - Comanche Switch 345kV	Flat Creek – Leon Switch 138kV	$6,125,626.21	52.43%
N_W	DCKT Comanche Switch - San Angelo Red Creek 345kV	Flat Creek – Leon Switch 138kV	$1,608,457.00	13.77%
N_W	DCKT Graham - Benbrook & Parker 345kV	Flat Creek – Leon Switch 138kV	$1,263,529.13	10.82%
S_N	DCKT Zorn - Austrop & Lytton Spring 345kV	Canyon - Rohr 138kV	$(13,486,519.15)	73.81%
W_N	SCKT Fisher Road - Oklaunion & Bowman 345kV	Graham - Long Creek 345kV	$47,774,440.25	64.36%
W_N	SCKT Fisher Rd - Bowman 345kV	Abilene South - Putnam 138kV	$7,498,835.67	10.10%
W_N	SCKT Fisher Rd - Oklaunion & Bowman 345kV	Graham -Murray 138kV	$2,227,997.54	3.00%
W_N	DCKT Graham - Sweetwater & Long Creek 345kV	Abilene South - Putnam 138kV	$1,755,511.34	2.36%
W_N	SCKT Fisher Road - Oklaunion & Bowman 345kV	Bomarton - Seymour 69kV	$1,258,758.69	1.70%
W_N	SCKT Tonkawa Switch - Graham 345kV	Abilene South - Putnam 138kV	$630,863.91	0.85%

Table 2 shows the top congested contingency and overloaded element pairs for the January through May timeframe:

Contingency	Overloaded Element	total - ytd
Comanche Peak SES- Decordova SES & Wolf Hollow - Rocky Creek 345KV	Concord 345/138KV Autotransformer	8
Menard - Gillespie 138KV	Menard autotransformer 1	7
North Edinburg - Rio Hondo 345kV	South McAllen - Stewart Road 138kV	7
Temple Switch - Killeen Switch & Sandow Switch 345kV	Killeen Switch - Harker Heights South	7
Austrop 345/138kV auto #2	Austrop 345/138kV Auto #1	6
Decker - McNeil & Dessau - Daffin 138KV	Decker - Sprinkle 138KV	6
Matador – Paducah Clare Street 69kV	Girard Tap – DKEC Jayton 69kV	6
Matador - Paducah Clare Street/ SPUR 69kV	Matador - Paducah REA Tap 69kV	6

Contingency	Overloaded Element	total - ytd
Morgan Creek SES – Quail SW & Odessa EHV 345kv	Big Springs SW – Big Spring West 138kV	6
North Edinburg - Rio Hondo 345kV	South McAllen - Las Milpas 138kV	6
Odessa EHV - Morgan Creek SES - Quail Switch 345kV	Morgan Creek SES - Cal Energy 345kV	6
San Angelo Red Creek 345/138kV Auto #1	San Angelo Red Creek 345/138kV Auto #2	6
Spur 138/69kV Auto #1	Spur - Girard Tap 69kV	6

Note: counts provided are for the number of days these pairs appeared as congested.

Table 3 contains local congestion costs for the period January through June, 2008; these are the top ten congested contingency and overload element pairs thus far:

Contingency	Overloaded Element	Estimated Cost
Moss - Holt 138kV	Odessa North - North Cowden 69kV	$992,273
Menard - Gillespie 138kV	Menard 138/69KV Transformer	$918,948
Austrop – Sandow 345kV	Milano-Minerva area potential voltage collapse	$630,529
Temple Pecan Creek - Tradinghouse - Lake Creek 345kV	Ridge - Watson Chapel 138kV	$563,443
Calaveras - Skyline & Walzem Road 138kV	Calaveras – Ball Park 138kV	$562,468
Morgan Creek SES - CAL Energy 345kV	Big Springs Switch - Big Spring West 138kV	$512,003
Trinidad - Stryker Creek & Mt. Enterprise 345kV	Athens – Elkton 138kV	$479,106
San Angelo Red Creek – Bluff Creek 345kV	Abilene Mulberry Creek East Reactor Series 138kV	$445,831
Fisher Road – Oklaunion & Bowman 345kV	Lake Pauline Autotransformer 138/69kV	$386,078
Austrop 345/138kV Autotransformer #1	Austrop 345/138kV Autotransformer #2	$343,624

Note: dollars shown are estimates and not Settlement quality.

5. Projection of Future Congestion

The attached spreadsheet contains the 2009 annual congestion report from the 2007 Five-Year Plan. The elements are sorted based on shadow price.

2009_Congestion.xls

6. Cluster Analysis

Approximately 16 scenarios were reviewed by the Congestion Management Working Group. The scenarios contained in this document are the remaining three scenarios are being submitted to the Wholesale Market Subcommittee for a decision.

CSC	Scenario 3b	Scenario 3g	Scenario 3h	Scenario 3i (2)
N_H (1)	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit
N_S & S_N	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit
W_N & N_W	Graham-Benbrook/ Graham-Parker 345-kV double circuit	Graham-Long Creek/ Graham-Cook Field Road 345-kV double circuit	Sweetwater-Long Creek/ Abilene Mulberry Creek-Long Creek 345-kV double circuit	Sweetwater-Long Creek/ Abilene Mulberry Creek-Long Creek 345-kV double circuit

Notes:

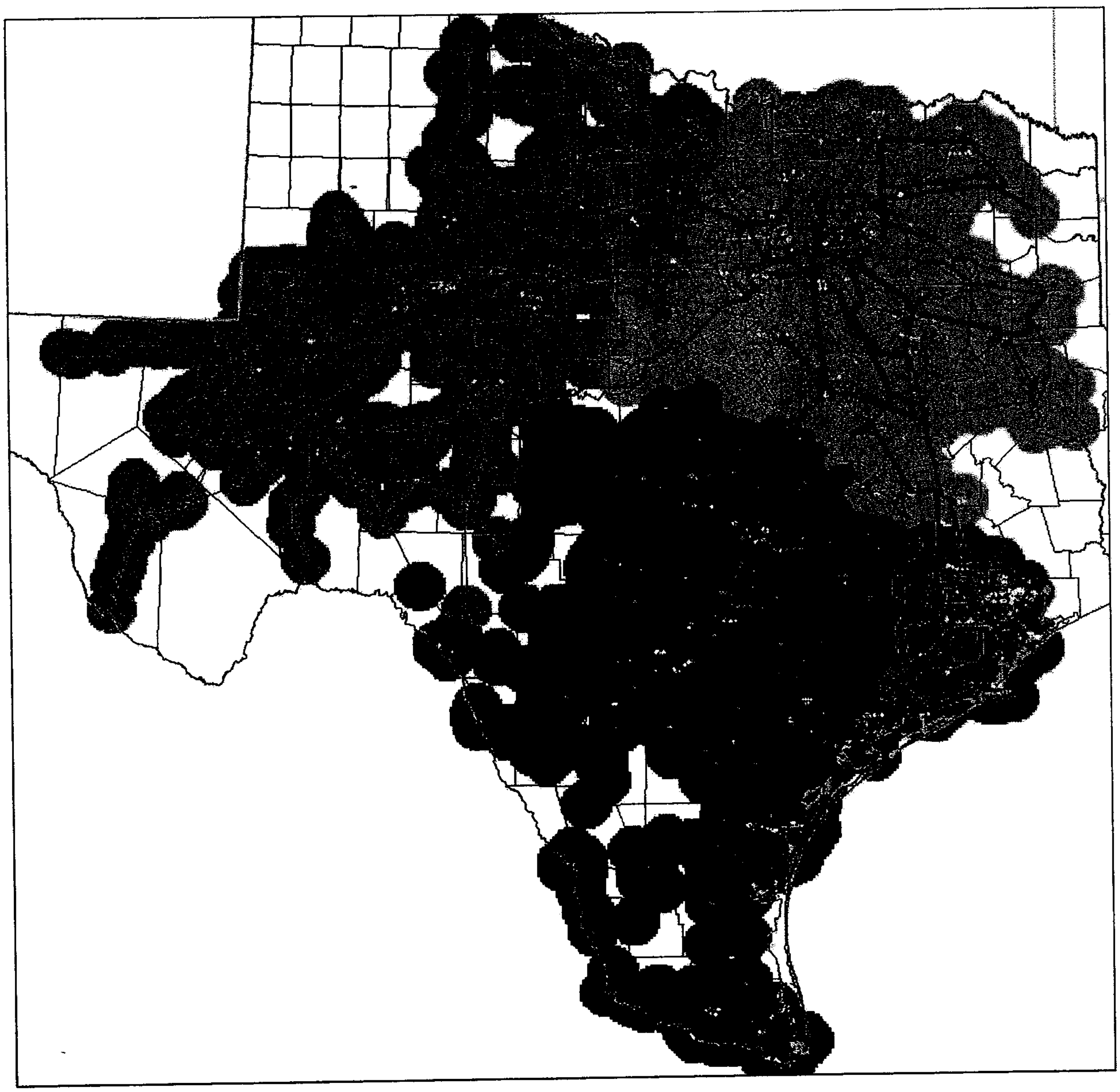
(1) For N_H, Singleton is not scheduled to be in-service until May 2009.

(2) Post-contingency (Oklaunion-Fisher Road/Fisher Road-Bowman 345-kV) shift factors were used for the clustering analysis.

6.1. Scenario 3b

Scenario 3b was clustered into four zones using the base case (with Singleton Switch Station). The 2008 CSCs were used with the following exceptions:

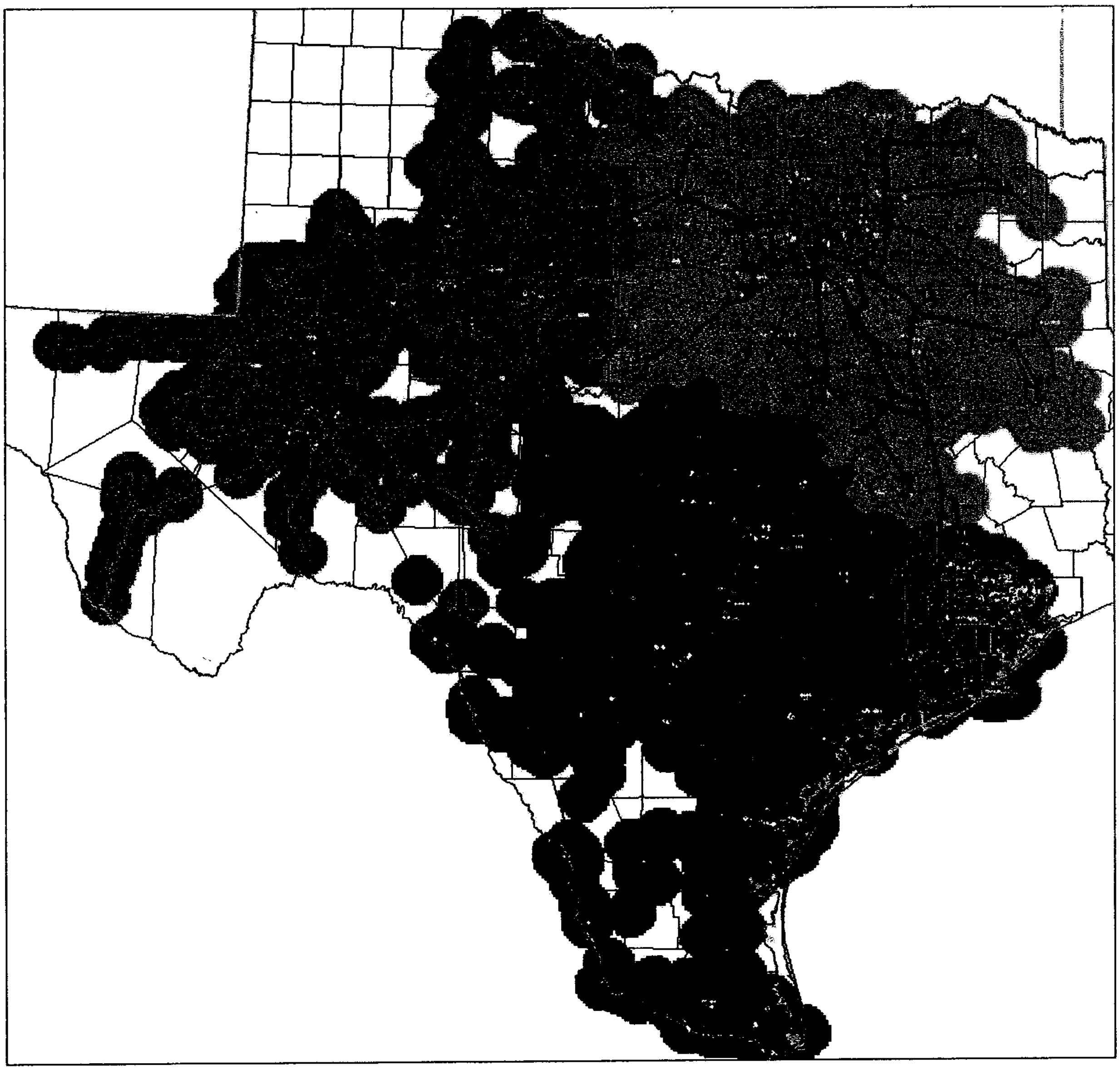
- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented using the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit.
- West to North/ North to West CSCs - represented using the Graham-Benbrook/ Graham-Parker 345-kV double circuit



6.2. Scenario 3g

Scenario 3g was clustered into four zones using the base case (with Singleton Switch Station). The CSCs were defined as follows:

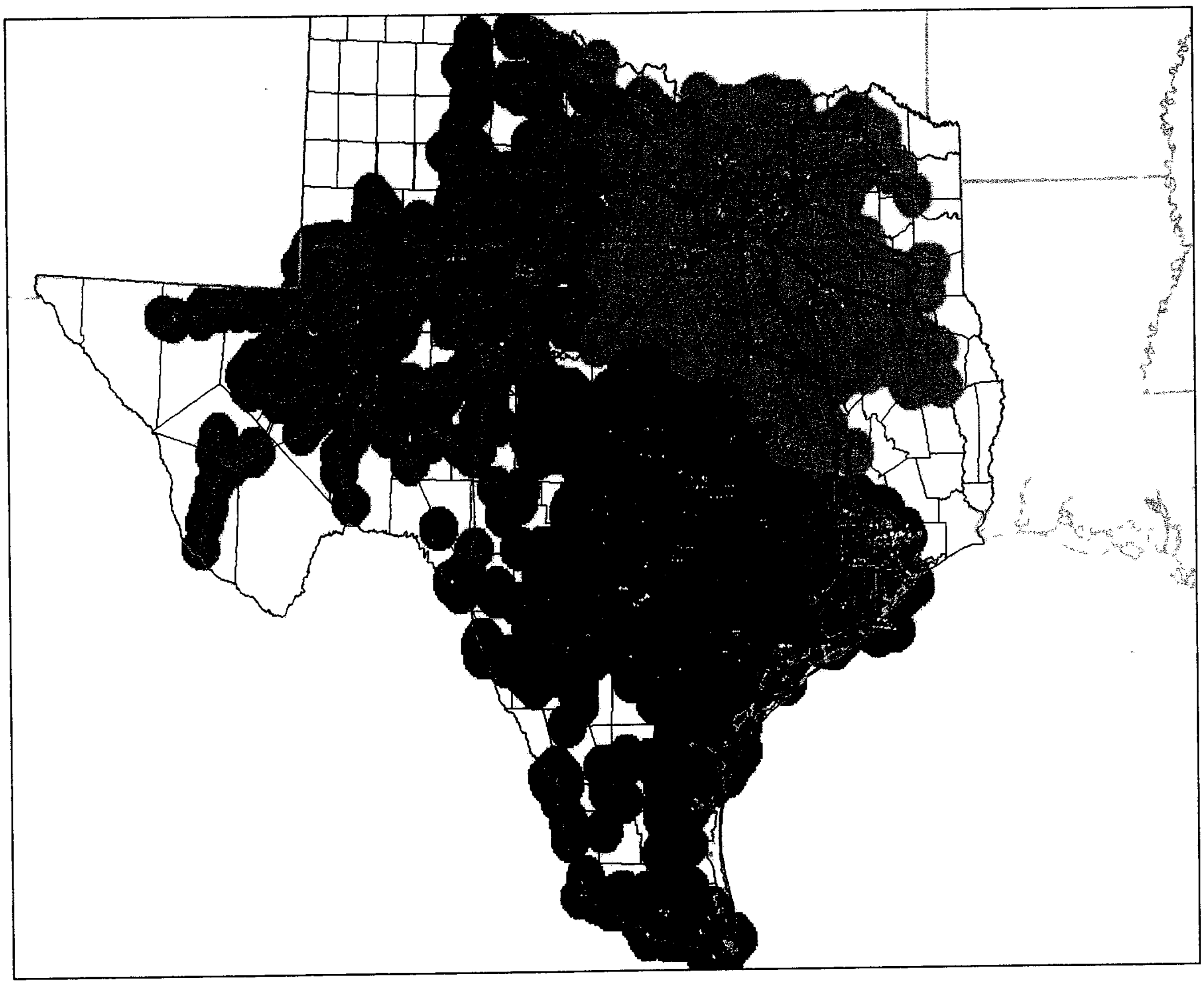
- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented using the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit;
- West to North/ North to West CSCs - represented using the Graham-Long Creek/ Graham-Cook Field Road 345-kV double circuit



6.3. Scenario 3h

Scenario 3h was clustered into four zones using the base case (with Singleton Switch Station). CSCs used:

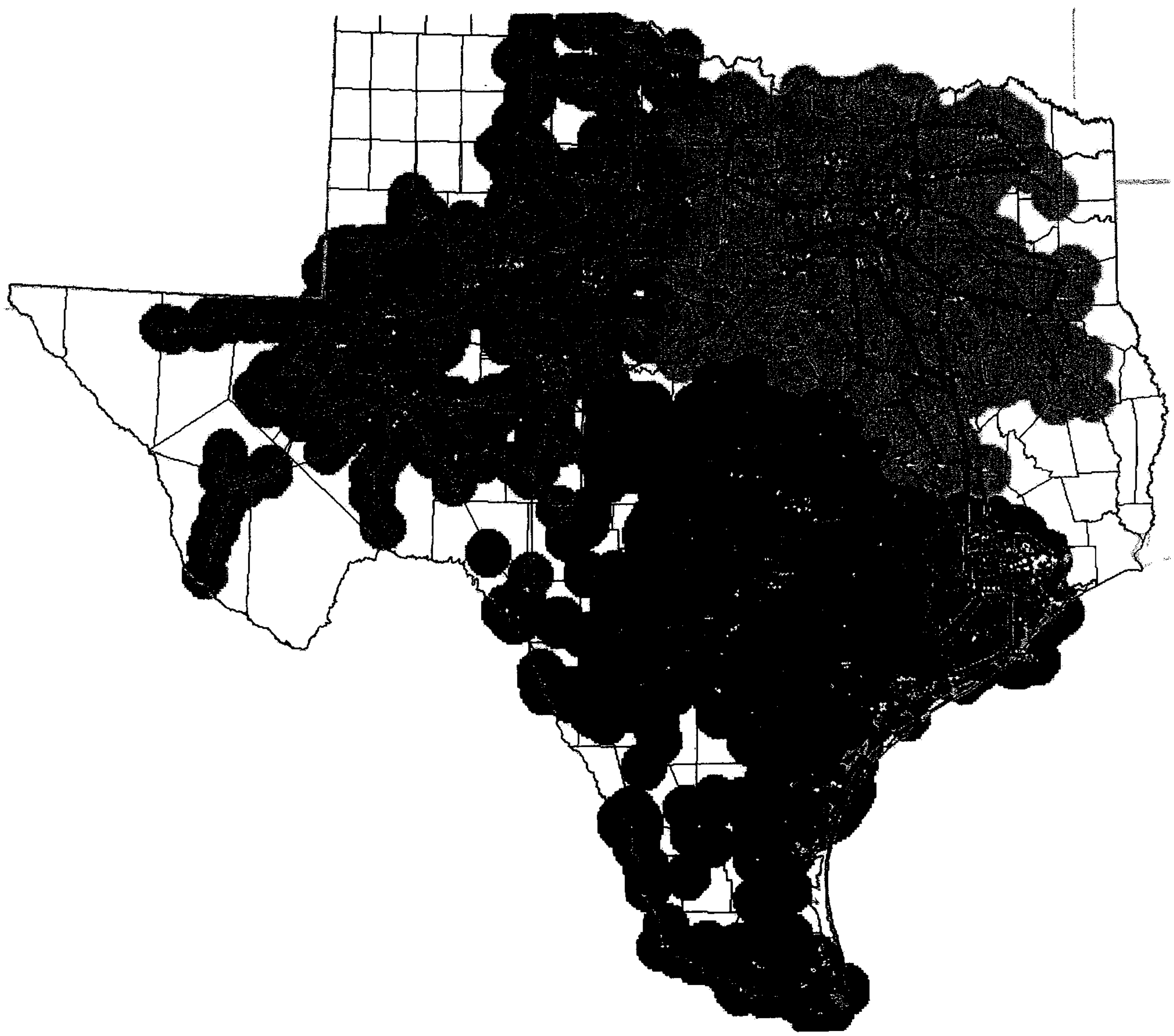
- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented by the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit;
- North to West/ West to North CSCs - represented by the;
- In this scenario Oklaunion moves to the North CM zone.



6.4. Scenario 3i

Scenario 3i was clustered into four zones using the base case (with Singleton Switch Station). CSCs used:

- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented by the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit;
- North to West/ West to North CSCs - represented by the Sweetwater-Long Creek/ Abilene Mulberry Creek-Long Creek 345-kV double circuit.
- Post-contingency (Oklaunion-Fisher Road/Fisher Road-Bowman 345-kV) shift factors were used for the clustering analysis.
- In this scenario Oklaunion remains in the West CM zone.



6.5. Shift-factor Impacts

Generation moving zones when compared to the 2008 CM zone bus mapping:

Generation Changing Zones in Scenario 3g

Bus Number	Name	Gen MW	2008 CM Zone	Scenario 3g CM Zone	Fuel/ Tech
344	MRSSHPRD	12	West	North	Hydro
345	MRSSHPRD	12	West	North	Hydro
1432	GRHAMSES	366	West	North	Gas Steam
1433	GRHAMSES	242	West	North	Gas Steam
1479	WFCOGEN_	40	West	North	Gas
1482	WFCOGEN_	40	West	North	Gas
1600	BARTNWND	120	West	North	Wind

Generation Changing Zones in Scenario 3h

Bus Number	Name	Gen MW	2008 CM Zone	Scenario 3h CM Zone	Fuel/ Tech
344	MRSSHPRD	12	West	North	Hydro
345	MRSSHPRD	12	West	North	Hydro
1432	GRHAMSES	366	West	North	Gas Steam
1433	GRHAMSES	242	West	North	Gas Steam
1437	MESQUITW	400	West	North	Wind
1438	MESQUITW	236	West	North	Wind
1479	WFCOGEN_	40	West	North	Gas
1482	WFCOGEN_	40	West	North	Gas
1600	BARTNWND	120	West	North	Wind
6752	OKLA0A	649.67	West	North	Coal

Load moving zones when compared to the 2008 CM zone bus mapping:

	Scenario 3b	Scenario 3g	Scenario 3h	Scenario 3i
North to South	1137.39	1156.4	1150.38	1150.38
South to Houston	107.54	53.41	53.41	53.41
West to North	4.97	762.08	780.98	761.63
West to South	3.8	3.8	3.8	3.8
North to West	7.63	0	0	0
total	1261.33	1975.69	1988.57	1969.22

The attached spreadsheet contains the bus-CM zone mapping for all scenarios:

CM_Zone_Bus_Mapping.xls

This spreadsheet provides the shift factors for all buses in each scenario using bus number 2406 as the reference in each case.

CSC_Bus_SF.xls

This map represents the three scenarios being reviewed and the Stability Limit lines.

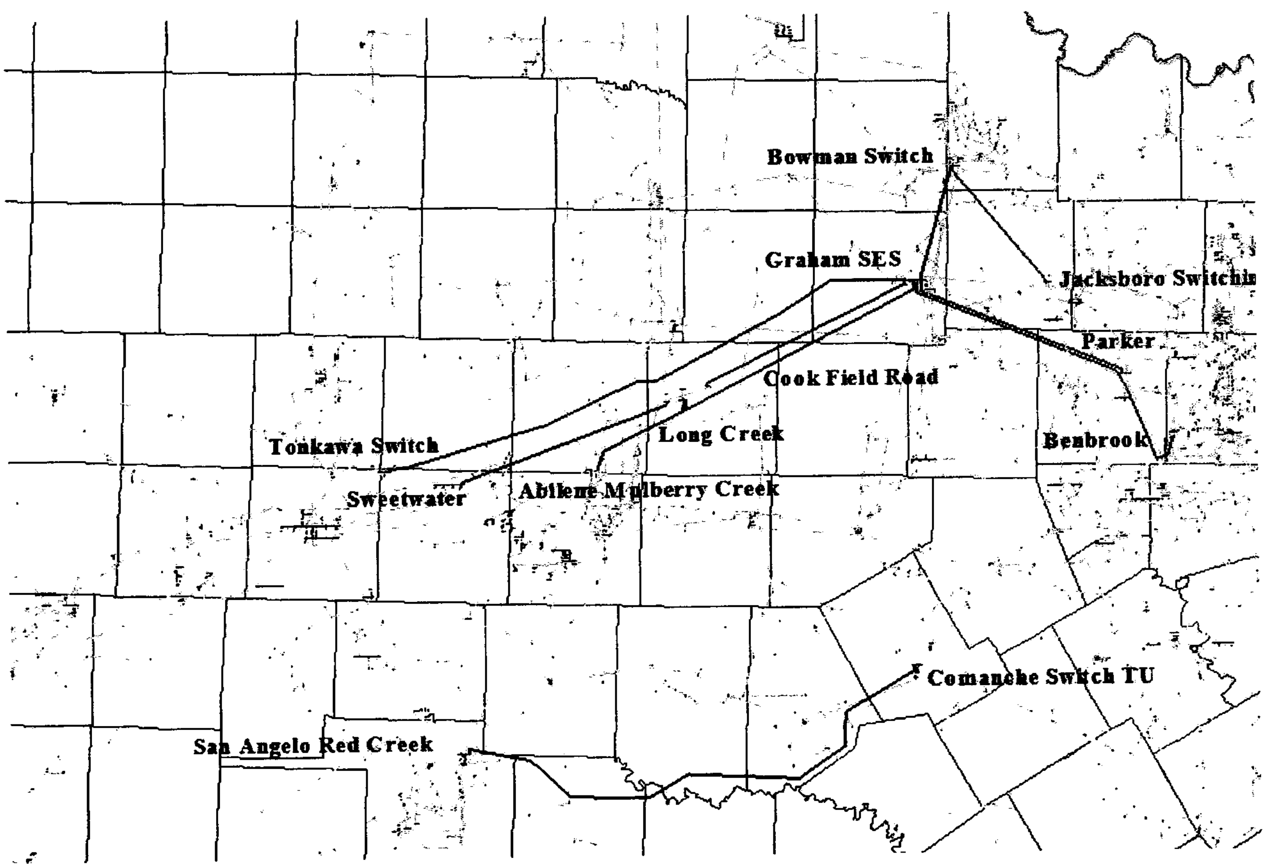


EXHIBIT 7

ERCOT

2009 CSC Study

Proposals

Version 3.2

Document Revisions

Date	Version	Description	Author(s)
07/02/2008	1.0	First draft	Jeff Billo
07/09/2008	1.1	Draft – added scenario 4	Jeff Billo
07/09/2008	1.2	Draft – added 2008 congestion data and minor edits	Isabel Flores
07/10/2008	1.3	Add scenario 5 and congestion costs	Isabel Flores
07/16/2008	2.0	Add scenarios 3a, 3b, 3c, 3d, 3e	Jeff Billo
07/21/2008	2.1	Add scenarios 3f, 6a, 6b, 6c	Jeff Billo
07/24/2008	3.0	Add scenario 3g	Jeff Billo
08/01/2008	3.1	Revised to show only the 3 options being submitted to WMS for consideration.	Isabel Flores
08/13/2008	3.2	Added scenario 3h and at the request of Market Participants' only scenarios 3b, 3g, and 3h are shown in this document version..	Isabel Flores

Table of Contents

2009 CSC Determination Study

1. Background

Protocol Section 7.2.1 requires ERCOT Staff to conduct an annual analysis to determine the upcoming year's Commercially Significant Constraints (CSCs). This analysis may include a transfer study, an evaluation of past congestion costs, and a projection of congestion costs for the upcoming year; ERCOT's analysis includes all of these features.

2. 2009 Significant Changes to the ERCOT grid

Per the May 2008 TPIT, these are the significant transmission projects scheduled to go in-service by the end of 2009:

1. Jack Creek 345/138-kV substation and associated projects (Sept. 2008)
2. Brownwood-Goldthwaite 138-kV line reconductor (Dec. 2008)
3. Singleton Switch (May 2009)
4. Waller-Prairie View-Seaway-Macedonia 138-kV line upgrade (Sept. 2009)
5. West Levee-Norwood 345-kV line (Dec. 2009)
6. Leon-Flat Creek 138-kV line upgrade (Dec. 2009)

Generation projects scheduled to go in-service by the end of 2009:

1. Victoria Power Station (July 2008)
2. Bosque Expansion (Mar. 2009)
3. Dansby 3 (Apr. 2009)
4. VH Braunig Peakers (May 2009)
5. Oak Grove 1 (July 2009)
6. Sandow 5 (July 2009)
7. Winchester (July 2009)
8. Sandhill Peakers (Nov. 2009)
9. 7981 MW (total) of west Texas wind, 173 MW of north Texas wind, and 590 MW of south Texas wind scheduled to be in-service by the end of 2008
10. 8206 MW of west Texas wind, 173 MW of north Texas wind, and 688 MW of south Texas wind scheduled to be in-service by September 2009

3. Transfer Study

The Steady State Working Group (SSWG) 2009 Data Set A 2009 summer peak base case was used for the transfer analysis. A congestion management (CM) zone to CM zone transfer analysis was performed by mapping all generators to their respective 2008 CM zones. New generation units were mapped to their assumed CM zone.

Transfer analysis was performed for the following zone to zone generation transfers:

1. West to North
2. South to North
3. North to South
4. North to Houston
5. North to West

The Singleton Switch Station was included in the base case because it is scheduled to be in-service by May 2009. However, since it will not be in-service for all of 2009 a second transfer analysis was performed. The base case was modified by removing the Singleton Switch Station and replacing the connected branches with the existing branch data for the Jewett-Tomball, Jewett-TH Wharton, Gibbons Creek-Roans Prairie, and Gibbons Creek-Obrien 345-kV lines. The North to Houston transfer study was rerun on the modified base case.

The results of the transfer studies are presented in the attached spreadsheet:

2009_CSC_Transfer
_Analysis.xls

4. Evaluation of Current Congestion Events

Table 1 is an estimate of zonal congestion costs for the period January through May; costs were assigned to contingency and overloaded elements based on those identified when determining CSC limits:

CSC	Contingency	Overloaded Element	Costs	% of total
N_H	DCKT Jewett - TH Wharton & Tomball 345kV	Watson Chapel - Robertson 138kV	$59,822,113.66	66.52%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV DCKT Temple Switch – Lake Creek & Temple Pecan Creek 345 kV	Watson Chapel - Robertson 138kV Temple Pecan Creek – Temple 138kV	$30,914,645.57	42.48%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Lorena - Waco West 69 kV	$6,175,256.24	8.49%
N_S	DCKT Temple Pecan Creek - Tradinghouse & Temple Switch - Lake Creek 345kV	Watson Chapel - Robertson 138kV	$3,497,318.90	4.81%
N_S	DCKT Temple Switch - Lake Creek & Temple Pecan Creek 345 kV	Temple Pecan Creek - Temple 138kV	$ 2,999,633.29	4.12%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Waco - Waco West 69kV	$1,615,205.93	2.22%
N_S	DCKT Temple Pecan Creek - Tradinghouse & Temple Switch - Lake Creek 345kV	Waco West - Waco Woodway 138kV	$1,415,734.42	1.95%

CSC	Contingency	Overloaded Element	Costs	% of total
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Temple Creek - Temple Switch 138kV	$932,185.42	1.28%
N_S	DCKT Sandow - Temple 345 kV	Killeen Clark Road – Copperas Cove 138kV	$932,185.42	1.28%
N_S	DCKT Austrop - Sandow SW 345kV	Sandow SW - Salty 138kV	$90,688.89	0.12%
N_S	DCKT Temple Creek - Trading House & Temple Switch - Lake Creek 345kV	Waco Woodway - Waco West 138kV	$ 63,462.48	0.09%
N_W	SCKT San Angelo Red Creek - Comanche Switch 345kV	Flat Creek – Leon Switch 138kV	$6,125,626.21	52.43%
N_W	DCKT Comanche Switch - San Angelo Red Creek 345kV	Flat Creek – Leon Switch 138kV	$1,608,457.00	13.77%
N_W	DCKT Graham - Benbrook & Parker 345kV	Flat Creek – Leon Switch 138kV	$1,263,529.13	10.82%
S_N	DCKT Zorn - Austrop & Lytton Spring 345kV	Canyon - Rohr 138kV	$(13,486,519.15)	73.81%
W_N	SCKT Fisher Road - Oklaunion & Bowman 345kV	Graham - Long Creek 345kV	$47,774,440.25	64.36%
W_N	SCKT Fisher Rd - Bowman 345kV	Abilene South - Putnam 138kV	$7,498,835.67	10.10%
W_N	SCKT Fisher Rd - Oklaunion & Bowman 345kV	Graham -Murray 138kV	$2,227,997.54	3.00%
W_N	DCKT Graham - Sweetwater & Long Creek 345kV	Abilene South - Putnam 138kV	$1,755,511.34	2.36%
W_N	SCKT Fisher Road - Oklaunion & Bowman 345kV	Bomarton - Seymour 69kV	$1,258,758.69	1.70%
W_N	SCKT Tonkawa Switch - Graham 345kV	Abilene South - Putnam 138kV	$630,863.91	0.85%

Table 2 shows the top congested contingency and overloaded element pairs for the January through May timeframe:

Contingency	Overloaded Element	total - ytd
Comanche Peak SES- Decordova SES & Wolf Hollow - Rocky Creek 345KV	Concord 345/138KV Autotransformer	8
Menard - Gillespie 138KV	Menard autotransformer 1	7
North Edinburg - Rio Hondo 345kV	South McAllen - Stewart Road 138kV	7
Temple Switch - Killeen Switch & Sandow Switch - 345kV	Killeen Switch - Harker Heights South	7
Austrop 345/138kV auto #2	Austrop 345/138kV Auto #1	6
Decker - McNeil & Dessau - Daffin 138KV	Decker - Sprinkle 138KV	6
Matador – Paducah Clare Street 69kV	Girard Tap – DKEC Jayton 69kV	6
Matador - Paducah Clare Street/ SPUR 69kV	Matador - Paducah REA Tap 69kV	6

Contingency	Overloaded Element	total - ytd
Morgan Creek SES – Quail SW & Odessa EHV 345kv	Big Springs SW – Big Spring West 138kV	6
North Edinburg - Rio Hondo 345kV	South McAllen - Las Milpas 138kV	6
Odessa EHV - Morgan Creek SES - Quail Switch 345kV	Morgan Creek SES - Cal Energy 345kV	6
San Angelo Red Creek 345/138kV Auto #1	San Angelo Red Creek 345/138kV Auto #2	6
Spur 138/69kV Auto #1	Spur - Girard Tap 69kV	6

Note: counts provided are for the number of days these pairs appeared as congested.

Table 3 contains local congestion costs for the period January through June, 2008; these are the top ten congested contingency and overload element pairs thus far:

Contingency	Overloaded Element	Estimated Cost
Moss - Holt 138kV	Odessa North - North Cowden 69kV	$992,273
Menard - Gillespie 138kV	Menard 138/69KV Transformer	$918,948
Austrop – Sandow 345kV	Milano-Minerva area potential voltage collapse	$630,529
Temple Pecan Creek - Tradinghouse - Lake Creek 345kV	Ridge - Watson Chapel 138kV	$563,443
Calaveras - Skyline & Walzem Road 138kV	Calaveras – Ball Park 138kV	$562,468
Morgan Creek SES - CAL Energy 345kV	Big Springs Switch - Big Spring West 138kV	$512,003
Trinidad - Stryker Creek & Mt. Enterprise 345kV	Athens – Elkton 138kV	$479,106
San Angelo Red Creek – Bluff Creek 345kV	Abilene Mulberry Creek East Reactor Series 138kV	$445,831
Fisher Road – Oklaunion & Bowman 345kV	Lake Pauline Autotransformer 138/69kV	$386,078
Austrop 345/138kV Autotransformer #1	Austrop 345/138kV Autotransformer #2	$343,624

Note: dollars shown are estimates and not Settlement quality.

5. Projection of Future Congestion

The attached spreadsheet contains the 2009 annual congestion report from the 2007 Five-Year Plan. The elements are sorted based on shadow price.

2009_Congestion.xls

6. Cluster Analysis

Approximately 16 scenarios were reviewed by the Congestion Management Working Group. The scenarios contained in this document are the remaining three scenarios are being submitted to the Wholesale Market Subcommittee for a decision.

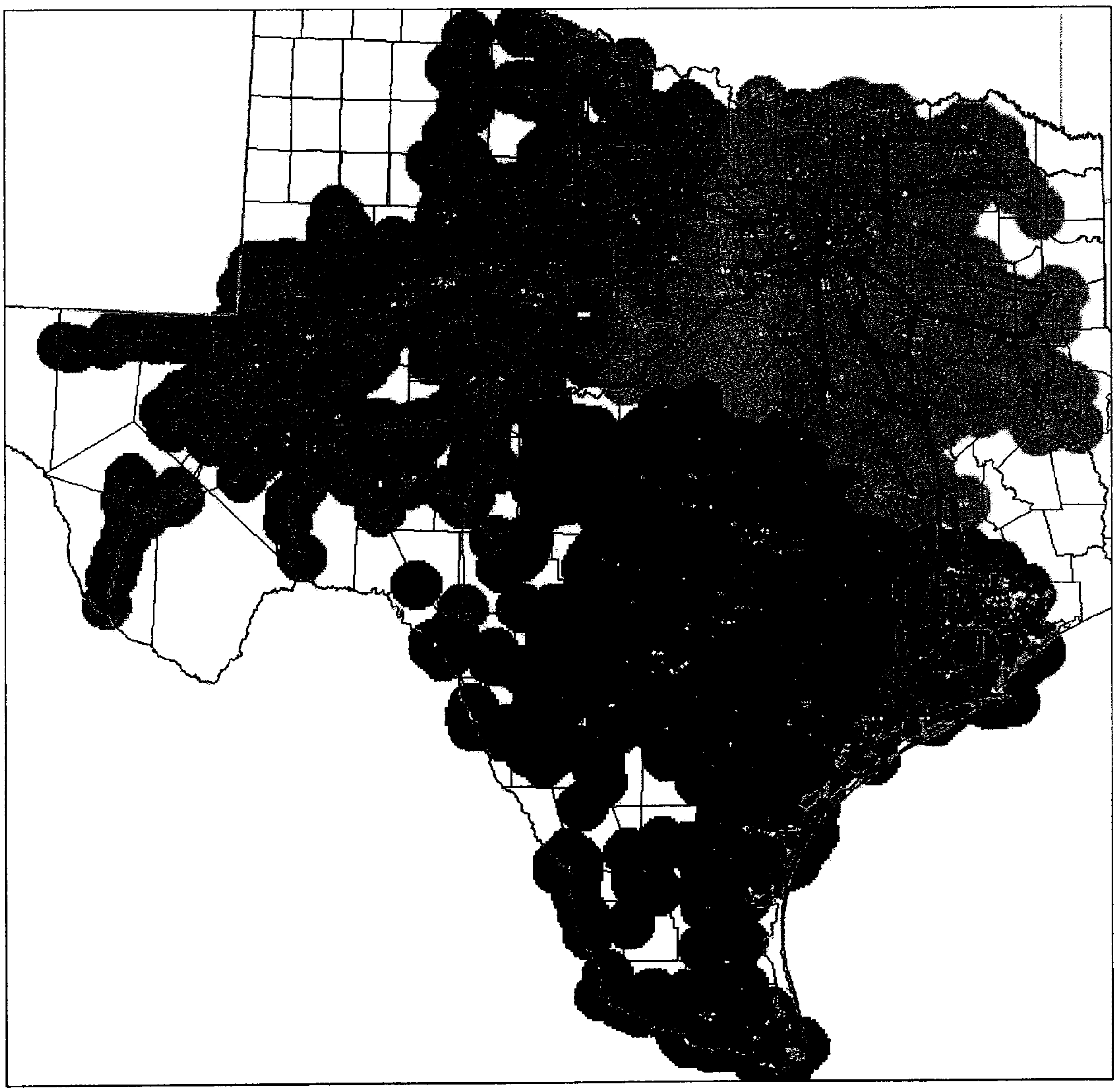
CSC	Scenario 3b	Scenario 3g	Scenario 3h
N_H*	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit	Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit
N_S & S_N	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit	Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit
W_N & N_W	Graham-Benbrook/ Graham-Parker 345-kV double circuit	Graham-Long Creek/ Graham-Cook Field Road 345-kV double circuit	Sweetwater-Long Creek/ Abilene Mulberry Creek-Long Creek 345-kV double circuit

Note: For N_H, Singleton is not scheduled to be in-service until May 2009.

6.1. Scenario 3b

Scenario 3b was clustered into four zones using the base case (with Singleton Switch Station). The 2008 CSCs were used with the following exceptions:

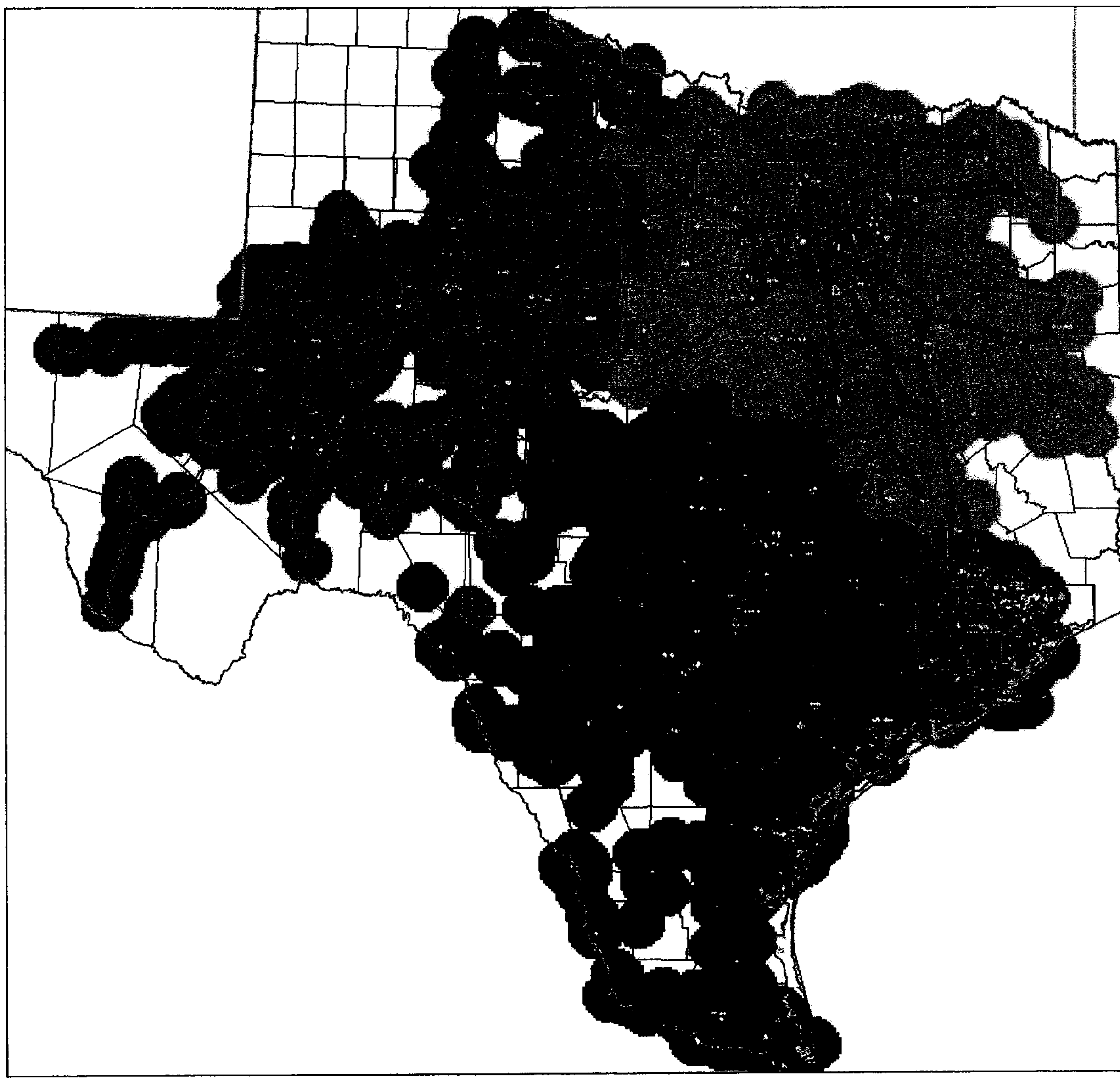
- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented using the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit.
- West to North/ North to West CSCs - represented using the Graham-Benbrook/ Graham-Parker 345-kV double circuit



6.2. Scenario 3g

Scenario 3g was clustered into four zones using the base case (with Singleton Switch Station). The CSCs were defined as follows:

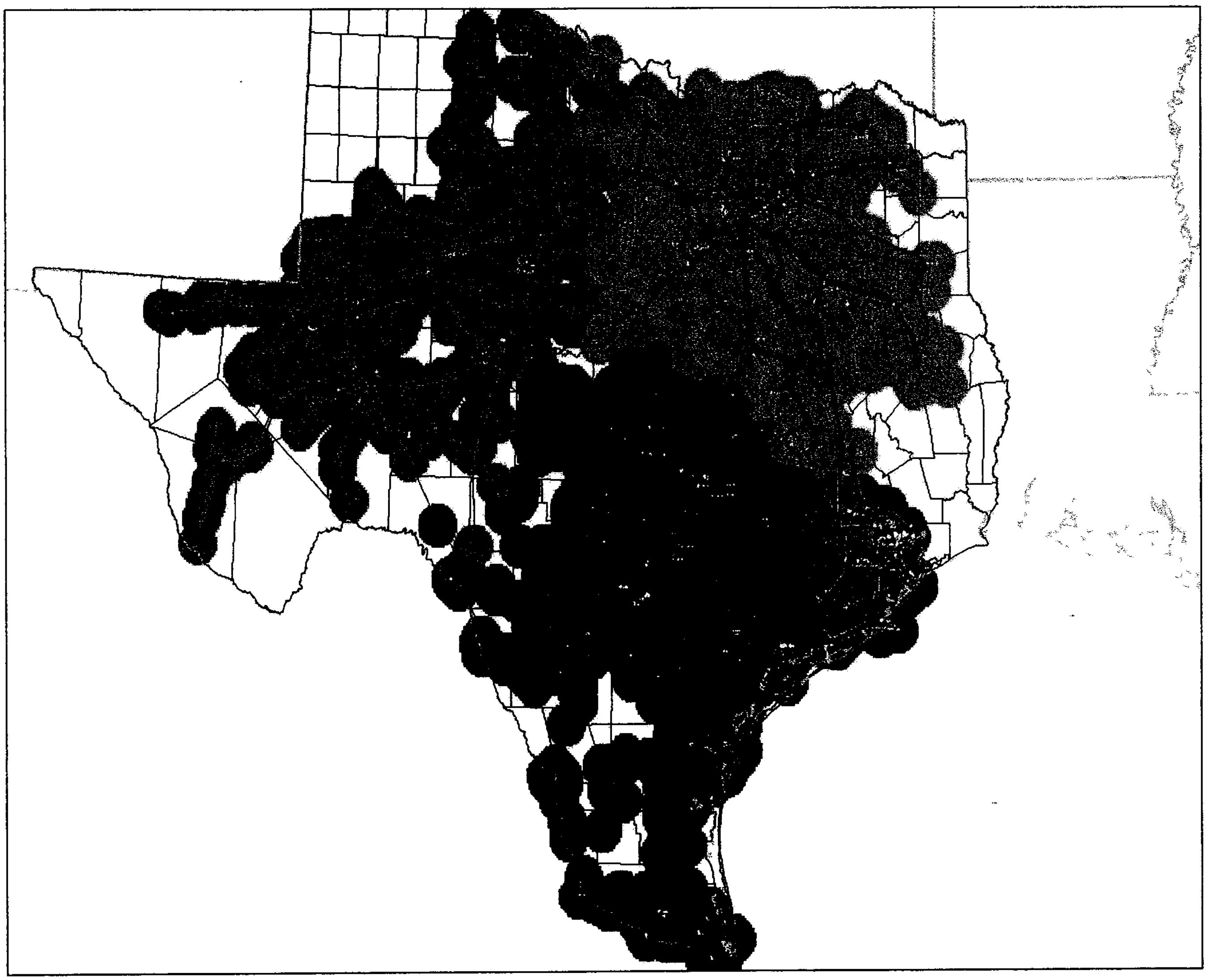
- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented using the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit;
- West to North/ North to West CSCs - represented using the Graham-Long Creek/ Graham-Cook Field Road 345-kV double circuit



6.3. Scenario 3h

Scenario 3h was clustered into four zones using the base case (with Singleton Switch Station). CSCs used:

- North to Houston CSC - represented by the Singleton-Obrien/ Singleton-TH Wharton 345-kV double circuit;
- North to South/ South to North CSCs - represented by the Lake Creek-Temple/ Tradinghouse-Temple Pecan Creek 345-kV double circuit;
- North to West/ West to North CSCs - represented by the Sweetwater-Long Creek/ Abilene Mulberry Creek-Long Creek 345-kV double circuit;
- In this scenario Oklaunion moves to the North CM zone.



6.4. Shift-factor Impacts

Generation moving zones when compared to the 2008 CM zone bus mapping:

Generation Changing Zones in Scenario 3g

Bus Number	Name	Gen MW	2008 CM Zone	Scenario 3g CM Zone	Fuel/ Tech
344	MRSSHPRD	12	West	North	Hydro
345	MRSSHPRD	12	West	North	Hydro
1432	GRHAMSES	366	West	North	Gas Steam
1433	GRHAMSES	242	West	North	Gas Steam
1479	WFCOGEN_	40	West	North	Gas
1482	WFCOGEN_	40	West	North	Gas
1600	BARTNWND	120	West	North	Wind

Generation Changing Zones in Scenario 3h

Bus Number	Name	Gen MW	2008 CM Zone	Scenario 3h CM Zone	Fuel/ Tech
344	MRSSHPRD	12	West	North	Hydro
345	MRSSHPRD	12	West	North	Hydro
1432	GRHAMSES	366	West	North	Gas Steam
1433	GRHAMSES	242	West	North	Gas Steam
1437	MESQUITW	400	West	North	Wind
1438	MESQUITW	236	West	North	Wind
1479	WFCOGEN_	40	West	North	Gas
1482	WFCOGEN_	40	West	North	Gas
1600	BARTNWND	120	West	North	Wind
6752	OKLA0A	649.67	West	North	Coal

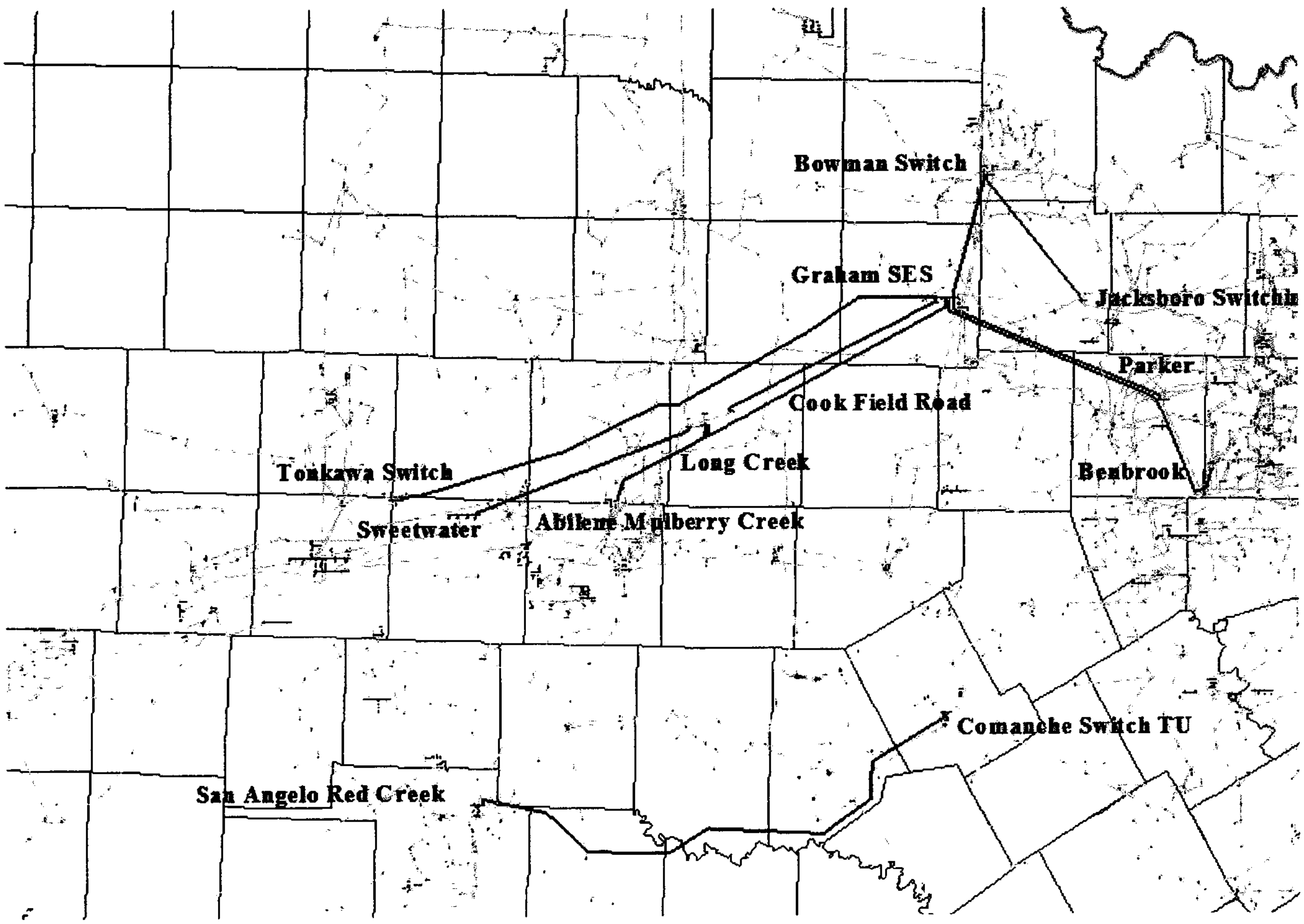
Load moving zones when compared to the 2008 CM zone bus mapping:

	Scenario 3b	Scenario 3g	Scenario 3h
North to South	1137.39	1156.4	1150.38
South to Houston	107.54	53.41	53.41
West to North	4.97	762.08	780.98
West to South	3.8	3.8	3.8
North to West	7.63	0	0
total	1261.33	1975.69	1988.57

The attached spreadsheet contains the bus-CM zone mapping for scenarios 3b, 3g, and 3h:

3b_3g_3h_Summary.xls

This map represents the three scenarios being reviewed and the Stability Limit lines.



APPROVED
Minutes of the Joint Emergency Technical Advisory Committee (TAC) and Wholesale Market Subcommittee (WMS) Meeting
ERCOT Austin – 7620 Metro Center Drive – Austin, Texas 78744
Wednesday, October 8, 2008 – 9:30am –1:30pm

Attendance

TAC Members:

Barrow, Les	CPS Energy	
Belk, Brad	LCRA	
Berend, Brian	Stream Energy	Alt. Rep. for E. Hendrick
Bivens, Danny	OPUC	
Boyd, Phillip	City of Lewisville	
Brewster, Chris	City of Eastland	
Brown, Jeff	Shell Energy	
Bruce, Mark	FPL Energy	
Clevenger, Josh	Brazos Electric Power Coop.	Alt. Rep. for H. Lenox
Comstock, Read	Strategic Energy	
Dreyfus, Mark	Austin Energy	
Greer, Clayton	J Aron & Company	
Gurley, Larry	Luminant	
Lange, Clif	South Texas Electric Coop.	Alt. Rep. for H. Wood
Lewis, William	Cirro Group	
McClendon, Shannon	Consumers – Residential	
Moss, Steven	First Choice Power	
Pieniazek, Adrian	NRG Texas	
Robinson, Oscar	Austin White Lime Company	
Ross, Richard	AEP	
Saenz, Fernando	Brownsville PUB	
Taylor, Jennifer	StarTex Power	Alt. Rep. for M. Zlotnik
Walker, DeAnn	CenterPoint Energy	Alt. Rep. for J. Houston
Whittle, Brandon	DB Energy Trading	

The following TAC Proxies were assigned:

- Kristy Ashley to Brandon Whittle
- Bill Smith to Oscar Robinson
- John L. Sims to Clif Lange
- Randy Jones to Adrian Pieniazek
- Cesar Seymour to Adrian Pieniazek
- David McCalla to Fernando Saenz
- DeAnn Walker to Manuel Muñoz

WMS Members:

Belk, Brad	LCRA
Berend, Brian	Stream Energy
Bruce, Mark	FPL Energy

Clemenhagen, Barbara	Topaz	
Clevenger, Josh	Brazos Electric Power Coop.	
Greer, Clayton	J Aron & Company	
Gurley, Larry	Luminant	
Hauk, Christine	Garland Power and Light	
Jackson, Tom	Austin Energy	
Lange, Clif	South Texas Electric Coop.	
McMurray, Mark	Direct Energy	
Miller, Gary	Bryan Texas Utilities	
Moss, Steven	First Choice Power	
Muñoz, Manuel	CenterPoint Energy	
Ögelman, Kenan	CPS Energy	
Pieniazek, Adrian	NRG Energy	
Ross, Richard	AEP	
Smith, Mark	Chaparral Steel	
Taylor, Jennifer	StarTex Power	
Torrent, Gary	OPUC	
Trenary, Michelle	Tenaska	Alt. Rep. for K. Emery
Whittle, Brandon	DB Energy Trading	

The following WMS Proxy was assigned:

- Kristy Ashley to Brandon Whittle

Guests:

Abernathy, Rick	Eagle Energy Partners
Bailey, Robert	NRG Energy
Bell, Wendell	TPPA
Brandt, Adrianne	Austin Energy
Cochran, Seth	RBS Sempra
Dohrwardt, Bray	Direct Energy
Firestone, Joel	Direct Energy
Garrett, Mark	Direct Energy
Goff, Eric	Reliant Energy
Jones, Don	Reliant
Ögelman, Kenan	CPS Energy
Rexrode, Caryn	Customized Energy Solutions
Soutter, Mark	Invenergy
Stephenson, Randa	Luminant
Wagner, Marguerite	PSEG
Wittmeyer, Bob	DME

ERCOT-ISO Staff:

Albracht, Brittney
Flores, Isabel
Goodman, Dale
Gage, Theresa
Garza, Beth
Hobbs, Kristi

Unless otherwise indicated, all Market Segments were present for a vote.

WMS Chair Brad Belk called the WMS meeting to order at 9:35am
TAC Chair Mark Dreyfus called the TAC meeting to order at 9:35 a.m.

Antitrust Admonition

Mr. Dreyfus directed attention to the Antitrust Admonition, which was displayed. A copy of the Antitrust Guidelines was available for review. Mr. Dreyfus reviewed assigned proxies and Alternate Representatives, reminded teleconference participants to employ their mute buttons, and announced that discussions would be held jointly, but that WMS would resolve discussions first, and then TAC would vote.

ERCOT Board of Directors (Board) Update Regarding TAC's 2009 Commercially Significant Constraint (CSC) Recommendation

Mr. Dreyfus reminded Market Participants that TAC approved a CSC scenario at the September 2008 TAC meeting, which was appealed by FPL Energy at the September 2008 Board meeting. Mr. Dreyfus reviewed the informal appeals process that was followed, and the resultant Board directive that TAC reconsider the 2009 CSCs along with consideration of Closely Related Elements (CREs) and boundary generator information.

Richard Ross noted that the procedure and late delivery of data was not an issue raised at TAC, but rather at the Board, and suggested a collective acknowledgement by WMS and TAC of ERCOT's subsequent efforts to deliver volumes of complex data on a compressed timeline might be helpful in stemming complaints of tardy data delivery. Mr. Dreyfus requested that the timeline for circulation of materials and revisions be reflected in the minutes:

September 17, 2008	Notice of October 8, 2008 Joint TAC/WMS Meeting
September 17, 2008	Notice of PTDF Coordination WebEx Meeting
October 1, 2008	Notice of October 8, 2008 Joint TAC/WMS Meeting Notice of October 6, 2008 WebEx Tech Review of CSC/CRE Data Delivery of Initial Materials (Agenda TAC WMS Meeting 20081008; 2009 CRE PTDFs.zip)
October 3, 2008	Delivery of Additional Materials (2009 CRE GSFs from MP.xls; 2009CREs_20081003-pub.xls))
October 6, 2008	Delivery of Additional Materials (Tech-Review20081006 v2.ppt; 3b_Boundary Gen.xls; 3h_Boundary Gen.xls; 3i_Boundary Gen.xls)
October 7, 2008	Delivery of Additional Materials (3i Boundary G updated v1.xls; CRES – Scenarios 3h 3i and 3b.ppt; 100608 FPL Energy CSC Presentation to TAC and WMS.ppt.)
October 8, 2008	Delivery of Additional Materials (CRRoss 100808.ppt; Graham and 2009 CSCs.ppt)

Mr. Belk opined that the market has been alert to the fact that significant data would be delivered on a compressed timeline, and has been engaged in the process. Mark Bruce added that while it is difficult for many Market Participants to become comfortable with the volume and timing of data, decisions frequently must be made in the face of imperfect information and options.

Review of 2009 CSC and Closely Related Element (CRE) Analysis (see Key Documents)
Beth Garza reviewed differences between Scenario 3h and Scenario 3i shift factor clustering, noting that Scenario 3i is post-contingency and believed to be justified due to topology. Ms. Garza noted that ERCOT legal has found the analysis process to be fully within the bounds of ERCOT Protocols.

Ms. Garza expressed her belief that as more Generation is installed to the west, and more Load to the east, there will be increasing attempted flows from the West zone to Dallas/FW, and that selecting Scenario 3i allows ERCOT Operations both local and zonal tools to manage congestion throughout the area. Ms. Garza reiterated that ERCOT will manage congestion under any scenario, and that there will be higher local congestion costs under Scenario 3i. Ms. Garza also stated her belief that Scenario 3b represents unpredictable and potentially explosive uplift costs if Transmission Congestion Rights (TCRs) are oversold, as the ability to project across the particular interface has not been particularly good, and will not improve dramatically any time soon.

Ms. Garza reviewed 2009 CREs for each scenario, and thanked Constellation, Direct Energy, and FPL Energy for their assistance in processing all the required analyses, including the Power Transfer Distribution Factor (PTDF), noting that the measure of how effective zonal balancing would be to relieve flows is very labor intensive and very valuable for analysis.

Market Participants discussed the impacts of specific lines and substations; that lessons from Spring 2008 taught that the CSC should be selected where congestion is expected to be centered; and the financial ramifications of overselling TCRs.

FPL Energy Presentation
Jan Bagnall presented FLP Energy's position for WMS and TAC consideration, and opined that the analysis to justify Scenario 3i is lacking, and that Market Participants and ERCOT need more time to consider costs. Mr. Bagnall suggested that some Market Participants do not understand the data and had essentially given their proxy to ERCOT in the CSC selection process. DeAnn Walker objected to Mr. Bagnall's characterization, stating that Market Participants spend significant time reviewing and analyzing the data.

Marguerite Wagner noted that Scenario 3b had been available for review since late June 2008; Mr. Bruce noted that Scenario 3b failed by a slim margin at WMS and that the ballot was available for review with the posted Key Documents.

Market Participants questioned Mr. Bagnall regarding the assumptions and resulting numbers in his presentation, and discussed that the Market Clearing Price for Energy (MCPE) cannot be guessed; and that CSCs should be selected based on where congestion is likely, and by what would provide the most efficiency. Ms. Wagner expressed frustration that the information was not presented at the Congestion Management Working Group (CMWG); Mr. Bagnall noted that Scenario 3i was also not presented at CMWG.

Luminant Presentation
Larry Gurley presented Luminant's position for WMS and TAC consideration highlighting statistics about Graham and West to North congestion for May 2008 through September 2008. Mr. Gurley stated

his interest in Graham moving to the North, as well as in getting the right answer, and noted that Luminant is the largest purchaser of wind energy under long-term contract.

AEP Presentation
Mr. Ross presented AEP's position for WMS and TAC consideration.

Mr. Ross moved that WMS endorse CSC selections in Scenario 3h and Scenario 3i, and eliminate Scenario 3b. Mark Smith seconded the WMS motion. Brandon Whittle opined that a good reason is needed to change CSCs after several years of stability, and requested that ERCOT restate its preference. Ms. Garza reiterated ERCOT's preference for Scenario 3i, and reviewed 2008 local and zonal congestion costs. Market Participants discussed that there is not a presumption of status quo; that history is considered in the selection process; and that there are always winners and losers. Chris Brewster expressed concern at moving the amount of Load represented in Scenario 3h and Scenario 3i.

The WMS motion to eliminate consideration of Scenario 3b carried on roll call vote with 75.6% in favor, 24.4% opposed and two abstentions from the Independent Generator Market Segment. Opposing votes were recorded in the Cooperative, Independent Generator (2) and Independent Power Marketer (IPM) (2) Market Segments. *(Please see ballot posted with Key Documents.)*

Kenan Ögelman moved that WMS endorse Scenario 3i for the 2009 CSCs, CREs, Transmission Congestion Zones and boundary generation Resources in the ERCOT transmission system. Mark Smith seconded the WMS motion. Mr. Ross requested permission to continue his presentation and voice his concerns regarding Scenario 3i.

Mr. Dreyfus noted that Mr. Ross' previous motion to endorse Scenarios 3h and 3i and eliminate Scenario 3b, subsequently seconded by Mr. Smith and carried on roll call vote, was acknowledged to be a WMS motion, and not a TAC motion, in accordance with the preference stated at the beginning of the meeting that WMS address business first, followed by TAC, and to which there were no objections. Mr. Dreyfus acknowledged Shannon McClendon's withdrawal of her second, as a TAC member, to Mr. Ross' WMS motion.

Mr. Ross opined that a process should be developed for post-contingency analysis, and that Scenario 3h should be the day's selection. Market Participants discussed clustering; the availability of non-wind generation in the West zone; and boundary generators. Mr. Ross asked Ms. Garza to confirm that ERCOT can operate the system reliably under either Scenario 3h or Scenario 3i, and that there would be sufficient generation in the West zone under Scenario 3h to resolve zonal congestion. Ms. Garza confirmed both statements as accurate.

The WMS motion to recommend approval of Scenario 3i carried on roll call vote with 82.5% in favor, 17.5% opposed and six abstentions in the Consumer, Independent Generator (3), IPM, and Municipal Market Segments. Opposing votes were recorded in the Investor Owned Utility (IOU) and Independent Generator Market Segments. *(Please see ballot posted with Key Documents.)*

Mr. Dreyfus noted the WMS recommendation of Scenario 3i to TAC and opened the floor to a TAC motion. Mr. Ross reiterated his objection to Scenario 3i, opined that WMS erred in the selection process, and stated that TAC is obligated to treat parties in a non-discriminatory manner.

Recommendation to the Board for 2009 CSCs and CREs

Mr. Ross moved that TAC endorse CSCs, CREs, zones and boundary generators associated with Scenario 3h. Clayton Greer seconded the motion. Mr. Ross opined that the modeling error implicit in the entire zonal market is also contained in the presented analysis; that overwhelming evidence is needed to change procedure to affect one unit as in Scenario 3i; that ERCOT could have developed a post-contingency analysis process, rather than applying it to just one unit, but did not; and that the dynamic stability issue is not fully understood. Ms. Garza assured Market Participants that ERCOT legal reviewed the Protocols to ensure ERCOT actions are in bounds; that the consideration remains how many MWs are trying to be passed over a stressed part of the transmission system; and that Power System Stabilizers (PSSs) at Oklaunion do not affect the fact that ERCOT is measuring the sum of flow across six lines. Ms. Wagner noted that ERCOT can utilize unit-specific instructions.

The TAC motion to recommend approval of Scenario 3h failed on roll call vote with two in favor, 23 opposed and five abstentions from the Consumer, Independent Generator (2), IPM, and Independent Retail Electric Provider (IREP) Market Segments. Opposing votes were recorded in the Cooperative (4), Municipal (4), IOU (3), Independent Generator (2), Consumer (5), IREP (3) and IPM (2) Market Segments. *(Please see ballot posted with Key Documents.)*

Danny Bivens moved that TAC adopt the WMS recommendation of Scenario 3i for the 2009 CSCs, Transmission Congestion Zones, CREs and boundary generation Resources in the ERCOT transmission system. Mr. Belk seconded the motion. The TAC motion carried with 22 in favor, six opposed and two abstentions from the Consumer and Independent Generator Market Segments. Opposing votes were recorded in the IOU, Independent Generator (2), Consumer (2), and IPM Market Segments. *(Please see ballot posted with Key Documents.)*

Mr. Ross stated that he would be filing an appeal and inquired about the timeline for Pre-assigned Congestion Rights (PCRs). Ms. Garza noted that the PCR allocations would be requested shortly after the October 2008 Board meeting and would be on a short timeline. Ms. Garza encouraged Market Participants to be alert to the process and abbreviated timeline. Mr. Greer opined that ERCOT Protocols might require revisions to address boundary generators in light of wind issues. Mr. Dreyfus requested that the item be taken up at the CMWG meeting.

Adjournment

Mr. Belk adjourned the WMS meeting at 1:35 p.m. Mr. Dreyfus adjourned the TAC meeting at 1:35 p.m.