OLIVER WYMAN

ERCOT
THE TEXAS CONNECTION

Corporate Risk

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TAC Credit Workshop
Selected slides

Austin, TX

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Contents

Section 1

Introduction and Results of Credit Practice Review

The entire credit evaluation project covered three workblocks

Workblock 1

Credit practices review

- Assessed ERCOT's current credit management practices
- Assessed ERCOT's current creditworthiness practices
- Examined nodal impacts

Workblock 2

Credit scoring model

- Developed a set of credit rating tools to assess probabilities of default (PD) for each participant
- Identified model factors based on financial data and qualitative assessments
- Tested against available benchmarks

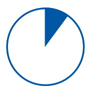
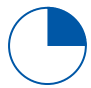
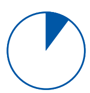
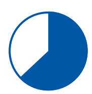
Workblock 3

Credit loss model

- Included collateral limits, price caps, other key assumptions as inputs
- Looked at possible volumetric exposures for each participant
- Simulated market prices, which with the volumes yield exposure at default (EAD)
- Simulated losses from credit failures
- Explored the impact of exogenous variables/ stress events

Credit Practice Review – Summary Results

ERCOT's credit worthiness monitoring & reporting and workout and management practices were found to be very solid. However, in the following areas ERCOT fell short of "best practices":

Category	Priority level	Calibration relative to best practice	Status achieved at the end of the project	Initial practice	Progress achieved during this project	Potential next steps
Risk appetite	High			• Some internal discussion in market meetings	• Risk appetite definition should be explicitly defined to better guide ERCOT's risk policies • Estimate credit risk using credit loss model (current OW effort)	• Assess market's comfort level with loss estimates and ability to absorb losses • Board should develop a formal risk appetite statement • Ensure credit policies and procedures are consistent with risk appetite and tolerance
Credit Scoring	Medium			• Agency ratings used where available but primarily for limit setting purposes • Creditworthiness was assessed using risk factors common to credit scoring models.	• Internal scoring model fully vetted and now available to supplement agency ratings	• Refine credit scoring model as additional data becomes available

Credit Practice Review – Summary Results

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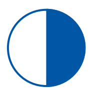
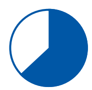
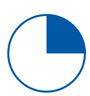
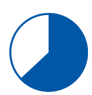
Category	Priority level	Calibration relative to best practice	Status achieved at the end of the project	Initial practice	Progress achieved during this project	Potential next steps
Exposure measure-ment and monitoring	High			▪ Exposure calculations track very recent historical exposure activity ▪ Measurement of forward exposure is based on recent history ▪ Processes are being automated ▪ Response to alerts is rapid and well-defined	▪ Credit loss model can simulate potential future exposure under a variety of assumptions and circumstances	▪ Forward exposure measurement should be based on forward risk factors (e.g. forward price and volume estimates)
Loss reserve and capital	High			▪ Some single scenario estimates have been made ▪ Based on historical market circumstances	▪ Credit loss model provide best practice capability ▪ Credit loss model will estimate loss magnitude	▪ Use economic capital results to foster discussion regarding risk appetite and a more consistent framework for considering loss reserves

Section 2

Credit Loss Model

Credit loss modeling

The questions this type of model addresses center on the potential for credit-related losses

Expected Loss

What level of credit losses is "normal"?

- Quarterly or annually
- This loss amount will vary, and is considered the **expected loss**
- Business must accommodate these

Economic Capital

What is the greatest loss we can expect?

- Over a given period
- For a given level of confidence
- Under a given set of assumptions
- Given a standard for solvency, can be used for determining **economic capital required**

How do changes to inputs affect potential losses?

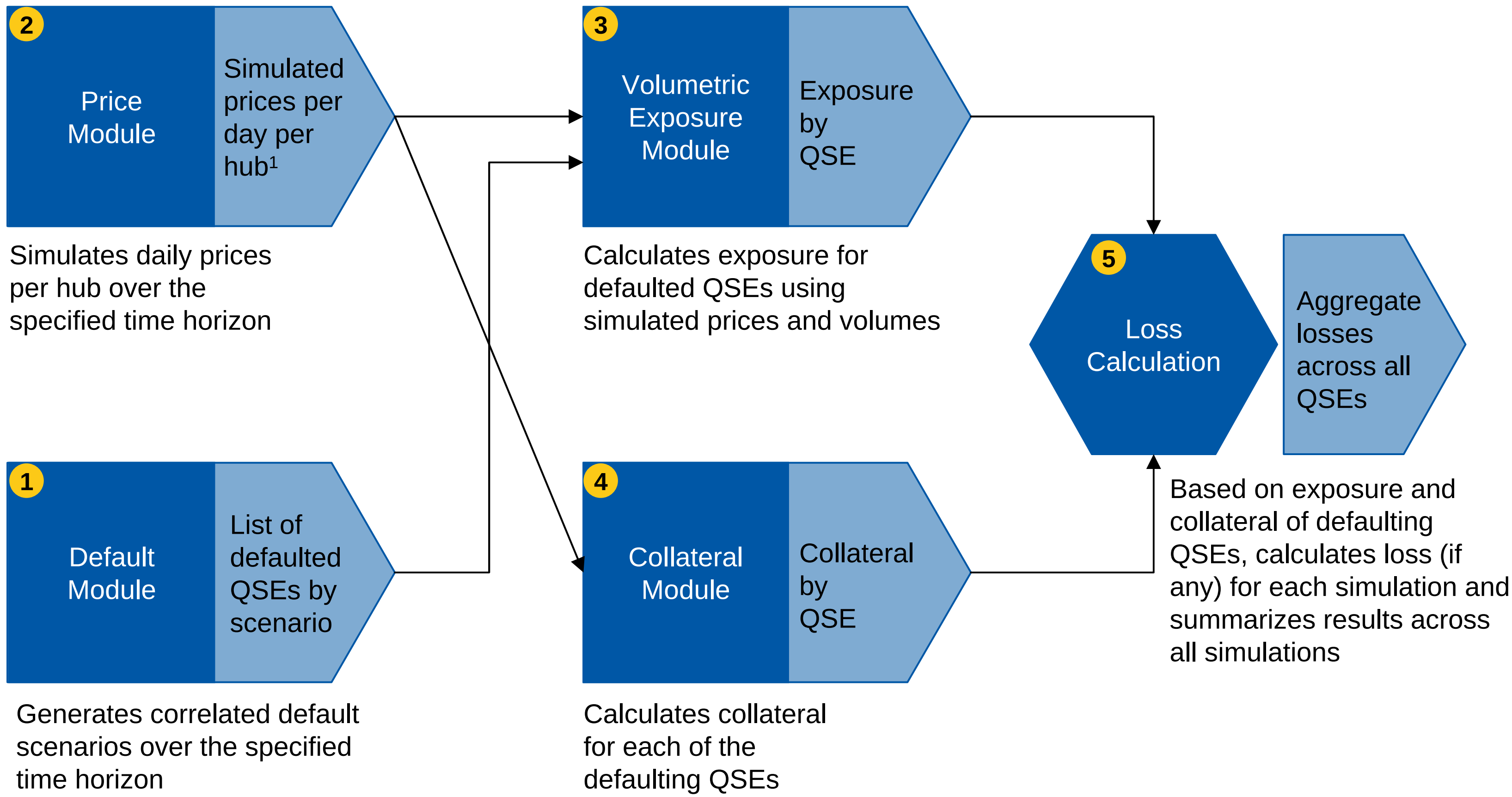
- Price cap levels
- Impact of credit and collateral rules
- Through process changes; billing cycle, mass transition handling, market rules
- Monitoring effort enhancements

Approach

- **Model the inputs of interest in a way that captures the important characteristics and relationships**
- **Simulate the resulting market environment and the occasional default of the participants**
- **Calculate the losses resulting from each simulation, and examine these statistics**

Credit Loss Model – High level credit loss calculation configuration

The model consists of four modules: default, price, volumetric exposure and collateral



The model will be run thousands of times in order to estimate a credit loss distribution – this schematic represents one simulation

1. Hub refers to a zone, settlement point, location or market

The model allows the user to make adjustments to inputs and measure how those changes impact the prospective distribution of credit losses

Global inputs

- Time horizon (in days)
- Number of simulations
- Number of hubs/zones
- Number of QSEs

Default module inputs

- Credit score of each QSE (i.e., probability of default)
- Default correlation types
- Market event sensitivity types

Price module inputs

- Price movement correlation between zones
- Forward prices predicted from forward gas prices, based on local spark spreads
- Frequency and size of jumps
- Jump event types (1-, 3-, 6-day jump series)
- Frequency of jumps common to multiple zones
- Locational differences that drive CRR pricing

Exposure module inputs

- Settlement and billing cycle
- Volume escalation behavior
- Maximum potential volume
- Length of time of mass transition (if applicable)

Collateral module inputs

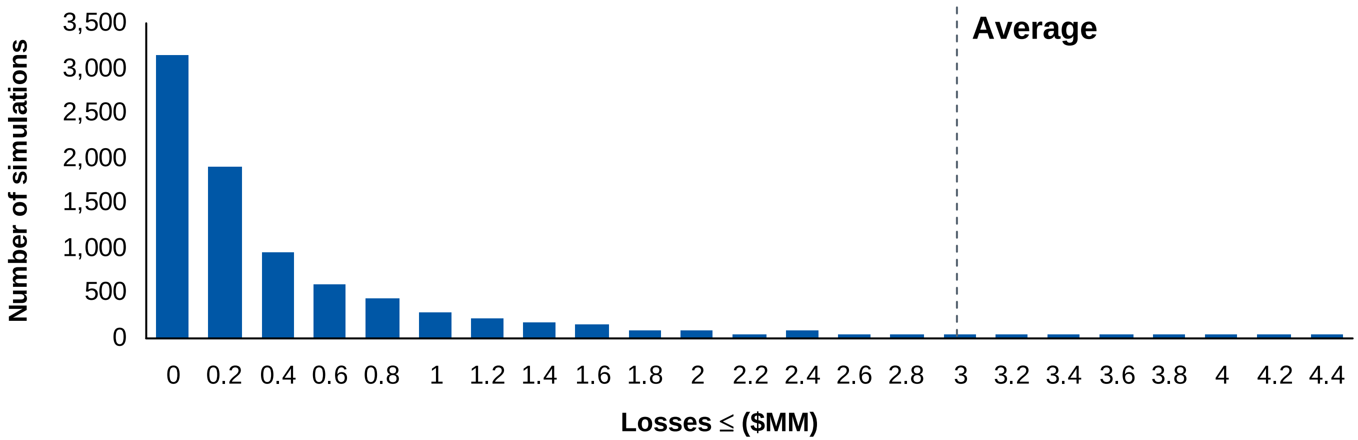
- Number of days to post collateral and cure a breach
- Simplified collateral calculations
- Collateral haircuts

Section 3

Model Results

Confidence levels in Monte Carlo analysis

Results: Baseline case showing 8,500 of 10,000 simulations



- Histogram shows number of simulations with credit losses less than, or equal, to X MM dollars
- Zero, or rather small, losses are the most common result
  - Almost a third (3,134) of the simulations had no losses; either no defaults or defaults with adequate collateral
  - The results show that 80% of the simulations result in losses that are less than $2,200,000 each (the first 12 bars total 7,993 simulations)
- The average loss across all simulations is about $3 MM
  - Most simulations are well below this, thus a few, rare, loss simulations have much greater losses
  - "Average" is **not** "most common outcome", but the long run average across all outcomes (the Expected Loss)
- These results are specific to one set of inputs, and one set of simulations
- The pattern shown here is common to virtually every analysis of ERCOT's market performed to date
  - All have a most common result of zero loss
  - All are heavily skewed to the right, showing only relatively rare, very large losses

Tabular results and comparison for the same Baseline case

- The baseline scenario reflects a combination of market and behavioral assumptions that are easily conceivable for the current market conditions and yields annual losses of
  - $16 MM at the once-in-20-years level
  - $43 MM at the once-in-100-years level
  - $99 MM at the once-in-1,000-years level
- The comparison stress scenario shown uses identical assumptions to the baseline except that all collateral actually held at the beginning of the period is recognized
  - Baseline assumes that all collateral holdings will meet but not exceed ERCOT's required minimums
- 50% of the annual credit losses were less than $194,000
- Most larger loss simulations are the result of several participants defaulting within the one year horizon
- While these estimates represent reasonable estimations of potential losses, actual losses may be more or less than these, as all possible scenarios are not addressed

	Baseline	Comparison
Average Loss	2.95	.742
Median	.194	.033
90.0^{th}%	8.26	1.38
95.0^{th}%	15.8	3.96
99.0^{th}%	42.6	10.9
99.9^{th}%	99.8	29.8
Maximum	213.0	156.0
Collateral held	Min. per Protocols	Actual historic

All losses in $ Millions

Frame of reference - Confidence levels in corporate finance

- This table shows historical default rates for firms with a variety of S&P credit ratings
- The "1-yr PD" is the likelihood a firm with this rating will default for any reason within one year.
- The "Confidence level" can be thought of as the likelihood that a firm with this rating will still be solvent after one year has passed, or the fraction of firms holding this rating that will remain solvent over the year
- Some firms use a target rating as a solvency standard
  - They manage their business so that the likelihood of bankruptcy within the next year equals the associated 1-yr PD
  - For example, if they target BBB+, the probability of insolvency must be about 0.1%
  - The amount of available assets the firm must hold to achieve this is its **economic capital requirement**

Rating	1-yr PD	Conf level
AAA	0.002%	99.9980%
AA+	0.003%	99.9970%
AA	0.005%	99.9950%
AA-	0.010%	99.9900%
A+	0.018%	99.9820%
A	0.033%	99.9670%
A-	0.059%	99.9410%
BBB+	0.108%	99.8920%
BBB	0.185%	99.8150%
BBB-	0.354%	99.6460%
BB+	0.642%	99.3580%
BB	1.164%	98.8360%
BB-	2.111%	97.8890%
B+	3.828%	96.1720%
B	6.943%	93.0570%
B-	12.59%	87.4080%
CCC+	22.84%	77.1620%

Choosing an appropriate confidence level

Typically driven by the needs of the various stakeholders

- Stakeholders that are typically considered:
  - Board, Management, Regulators, Debtholders, Shareholders,
  - Financial community ,Customers, Suppliers, Employees
- Selection of a confidence level typically hinges on these entities' expectations of solvency, and what level of assurance is needed to retain them as stakeholders
- Many firms with significant borrowing choose historical solvency levels associated with a target debt rating – as a way to drive towards particular bond ratings
- The market participants invest in this region (plant, human capital, etc) with the expectation that the ERCOT market will remain functional
- What expectation of solvency is appropriate for this market?
  - A higher target will increase assurance, and current costs (collateral, etc) for the participants but demand more from them in explicit support
  - A low target will decrease all of these
  - The size and visibility of the market argue strongly for an investment grade target
- Other strategic issues may also impact that choice, such as reputation, similarity to other ISOs, target growth in number of market participants or in a particular market segment

Section 4

Wrap Up and Next Steps

Did ERCOT get everything it wanted?

All of the project's objectives and deliverables have been achieved

- Specific project objectives:
  - Review of credit practices in ERCOT Protocols, Creditworthiness Standards, and credit risk management practices generally
  - Determine whether ERCOT's practices are consistent with best practices.
  - Provide modeling capability to enable quantification of credit risks for the entire credit portfolio.
  - Estimate Probabilities of Default (PDs) for each participant
  - Estimate the credit loss probability distribution using this model
  - Provide a capital adequacy assessment.
- Deliverables:
  - Evaluation of creditworthiness and credit management practices
  - Credit scoring model and documentation
  - Credit loss model with documentation
  - Loss distributions and capital adequacy evaluation

ERCOT also sought answers and insight into broader questions of risk tolerance

1) At a specific point in time and for a specific timeframe, we are xx% confident that the market will not have losses in excess of $xx.
   - The model OW delivered will allow ERCOT and the market to make this kind of statement under various assumption sets

2) At a specific point in time and for a specific time frame, we are xx% confident that the market can withstand losses of $xx.
   - OW explored various ways to accomplish this with ERCOT.
   - Ultimately, OW and ERCOT concluded that a model couldn't do this because ERCOT does not hold a central pool of capital to provide an economic buffer against credit losses (or any losses) and there is no way to know with certainty how each participant will respond to given levels of short pay or uplift.
   - ERCOT agreed that providing "confidence", if there was not a strong basis for the conclusions, would be counterproductive.

Potential next steps

- Examine any specific potential loss scenarios suggested by the Finance and Audit Committee and/or the Board
- Continued education and iteration on scenarios with stakeholders
- Pursue policy decision on level of acceptable credit exposure
  - Define an appropriate confidence level
  - Define a target “not to exceed” amount at the defined confidence level
  - Agree on the modeling assumptions to be used in the analysis

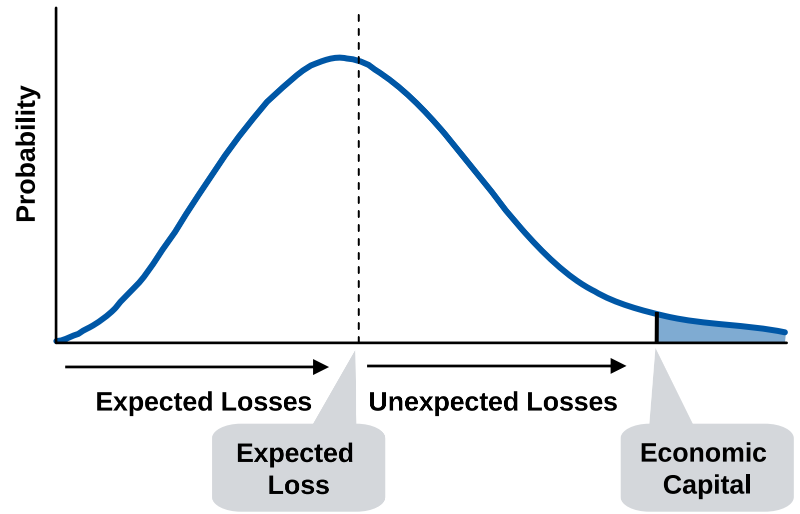
Section 5

Appendix

Credit loss and capital adequacy definitions

- **Capital adequacy (economic capital):** Based on the **portfolio analysis** and an assessment of the market, it is the amount of losses you may lose over a specified time period with probability X%
- **Expected Loss:** Long run statistical average of potential credit losses across a range of typical economic conditions
- **Portfolio analysis:** Aggregation of losses by counterparty across the market

Illustrative Loss Distribution



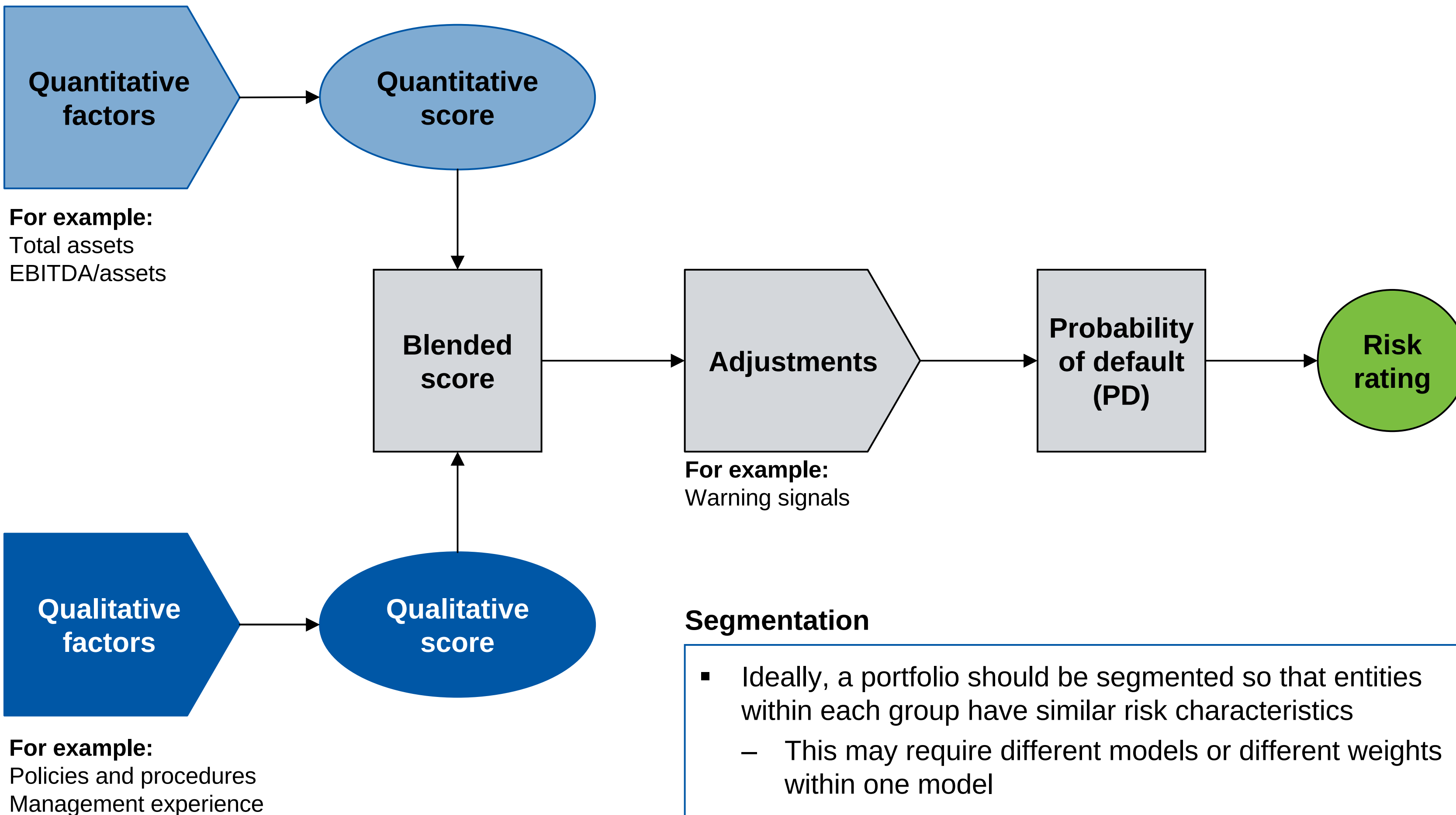
Terms used when measuring credit loss

- **Probability of default**: The probability that a counterparty will default at some point in a specified time horizon
  - **Default correlation:** Similarity of the counterparty to other counterparties in the portfolio in terms of common drivers of default (e.g. geography, industry, business model)
- **Exposure at Default:** Sum of the exposures at time of default for each counterparty over the specified time horizon
- **Loss given default:** Sum of exposures **in excess of collateral and other risk mitigation** at time of default for each counterparty over the specified time horizon

Near-term PD estimates for the capital adequacy model are approximated differently depending on the category a QSE falls under

Segment	Proposed approach
Non-rated with financials	▪ Credit scoring model used to rate this segment ▪ Quantitative score calculated from provided financials ▪ Qualitative score started out the same for each QSE, but ERCOT adjusted for highly positive or negative answers to qualitative questions
Non-rated without financials	▪ All QSEs in this segment receive a CCC+ rating ▪ Rating mapped to a PD
Publicly rated	▪ Public rating mapped to a PD
Special case for un-rated subsidiary with rated parent	▪ All QSEs in this segment receive a standalone CCC+ rating (if financials were not provided) or the rating from the credit scoring model ▪ Parent receives their public rating ▪ Group logic applied to determine strength of relationship between subsidiary and parent and QSE rating adjusted accordingly

A standard credit scoring approach blends quantitative and qualitative scores and potential adjustments, to arrive at a PD and risk rating



Segmentation

- Ideally, a portfolio should be segmented so that entities within each group have similar risk characteristics
  – This may require different models or different weights within one model
- Segmentation of a portfolio can be performed along different dimensions (e.g., size, sector)

The scoring approach groups output into a rating category with an associated midpoint PD so as not to overestimate precision

Example

Internal credit scoring model

Resulting PD

30bps

Map PD to a rating category

PD range (bps)	Rating	Midpoint PD (bps)
3-5	AAA-A+	4
5-10	A+-A-	8
10-15	BBB+	13
15-25	BBB	20
25-40	BBB-	33
40-80	BB+	60
80-135	BB	108
135-220	BB-	178
220-365	B+	293
365-600	B	483
600-1000	B-	800
> 1000[1]	CCC+	1500

Final output based on rating and midpoint PD

BBB
33bps

1. All lower PDs map to this rating

Selected financial and qualitative factors and weights

Quantitative factors

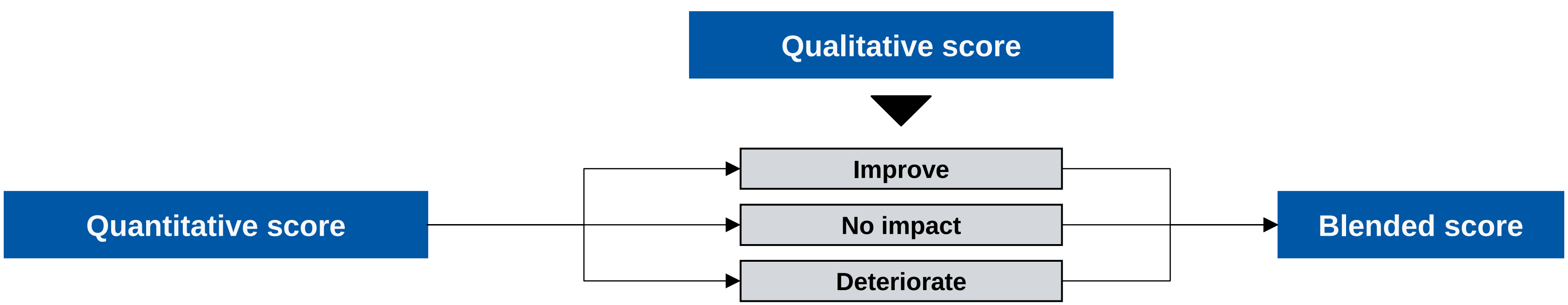
Proposed factor	Weight
Working Capital/Sales	30%
Current Ratio	10%
Equity/Assets	20%
EBITDA/Interest Expense	10%
EBITDA/Sales	10%
Net Income/Assets	10%
Total Assets	10%

Qualitative factors

Proposed factor	Weight
Ability to access funding in difficult market environment	25%
Margin call and late payment history	20%
Experience of company leadership	15%
Recent growth	15%
Risk management policies and practices	10%
Quality and timeliness of reporting of financial information	10%
Length of time as QSE	5%

70% weighting

30% weighting



Credit scoring results are used as input for credit loss modeling

- Oliver Wyman used the model assumptions discussed on the previous pages to arrive at initial Probabilities of Default (PDs) for each QSE
  - Some of these were agency ratings
  - Some were scored based on financials provided to ERCOT
  - Others were assigned CCC+ when no financials were provided
- All of these initial ratings were considered in light of any relationship between the participant and a parent (i.e., “Group Logic” was applied)
- Credit loss model treats capped guarantees with 30-day termination clauses as collateral
  - Where the guarantee is substantially in excess of EAL, should net same results
  - Best allows for all possible scenarios where and how entities use guarantees

Default correlation

Defaults between QSEs are correlated by common drivers

- Probabilities of default are user inputs, intended to feed directly from the internal credit scoring model
- Each QSE is associated with a "default correlation" type
  - These types are based on common drivers of default
  - These common drivers systematically increase the probability of QSEs within the same type (and across types) defaulting together
  - Selection of "default correlation" types should attempt to best segment the QSEs by common default drivers
- The proposed "default correlation" types are based on the primary business of each QSE as defined below

Default correlation type	Business	Definition
1	Generation	> 70% of combined load and generation volume is generation[1]
2	Small load	< 10,000 MWh/day of load (and < 30% of combined load and generation volume is generation) [1]
3	Large load	> 10,000 MWh/day of load (and < 30% of combined load and generation volume is generation) [1]
4	Trading	Minimal load or generation
5	Public power	Munis and coops
6	Mixed	Relatively balanced mix of load and generation

1 Based on average activity for a recent month.

Default events are correlated based on business type

	Generation	Small load	Large load	Trading	Public power	Mixed
Default type	**1**	**2**	**3**	**4**	**5**	**6**
1 Generation	20%					
2 Small load	0%	30%				
3 Large load	0%	20%	25%			
4 Trading	0%	0%	0%	10%		
5 Public power	10%	5%	10%	0%	20%	
6 Mixed	10%	5%	5%	5%	10%	20%

- Each individual QSE is assigned a “default correlation” type based on their business
- The correlations determine the likelihood that QSEs will default within the same timeframe, driven by the same underlying factors
- In other industries, default correlation within industry segments is 20-30%
- The correlations proposed are subjective, based on the business risk factors present in these enterprises

Defaults can either be market driven or non-market driven

"Market event sensitivity" types are used to determine how a QSE may have defaulted

- "Market event sensitivity" types are identified based on the likelihood of QSE defaults being closely associated with market events (e.g., price jumps)
  - If certain QSEs are more likely to have defaults near market events (high price days), the model needs to reflect this in order to accurately calculate exposure
- If the QSE's default is identified as being related to a market event, the prices near the default day are above a specified percentile
- If the QSE's default is identified as having no relation to a market event, the day of default will be randomly chosen over the time horizon of the analysis

Type	Description	Probability of defaulting near a "high price day"	"High price day" is defined as those in the upper
1	SR / LR	50%	90%
2	Gen, Trader, PP, Mixed	20%	90%

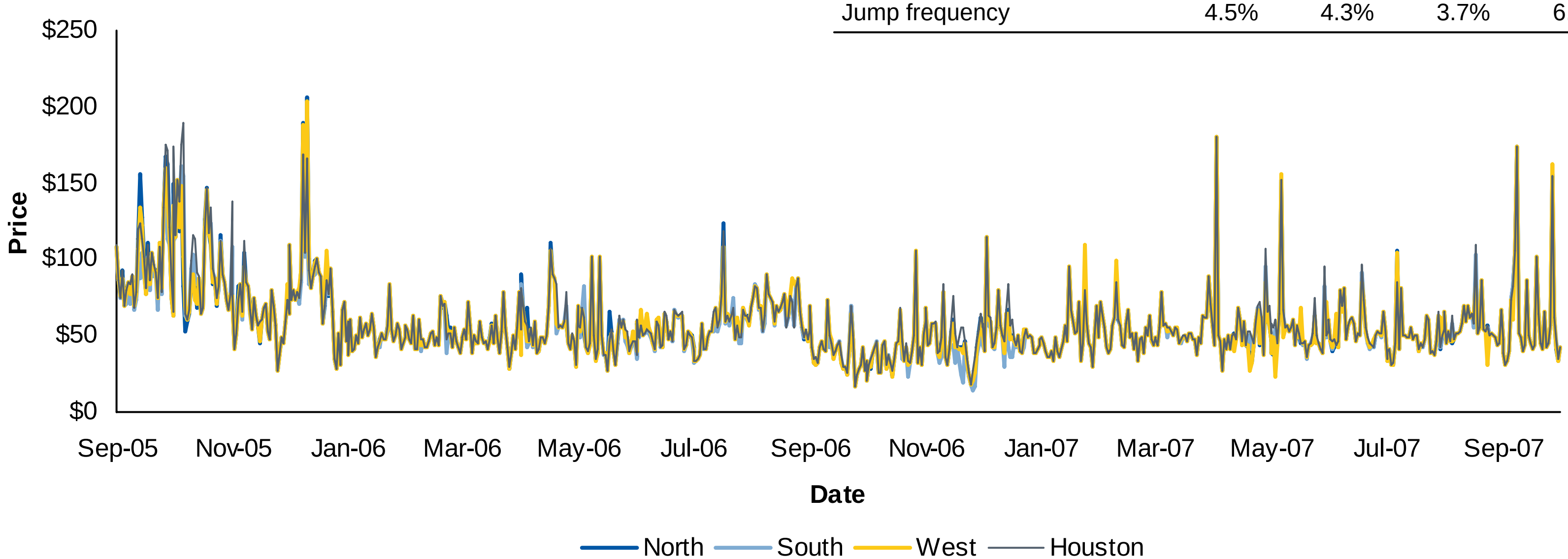
- Depending on a counterparty's market event sensitivity and type, volume escalation scenarios will be linked accordingly

Price jump analysis

Illustrative

- Identify jump cutoff levels
- Attempt to leave jumps and residual price changes "normal"
- Assumptions include
  - One common cutoff level vs individual cutoffs
  - Identical size jumps for concurrent events
  - Simple average daily prices vs weighted averages

Jump cutoff	105	103	107	98
Observed price days	760	760	760	760
Observed jump days	34	33	28	47
Avg jump size (above mean)	76.1	68.9	78.3	69.5
St dev jump size	27.8	23.0	27.2	27.0
Skew[1]	0.922	0.937	0.930	0.887
Kurtosis[2]	-0.091	-0.346	-0.033	-0.648
J-B test for normality	4.687	4.357	3.998	4.892
Normal?	Normal	Normal	Normal	Normal
Jump frequency	4.5%	4.3%	3.7%	6.2%



1 Skew characterizes the degree of asymmetry of a distribution around its mean.
2 Kurtosis characterizes the relative peakedness or flatness of a distribution compared with the normal distribution.

Proposed market price characteristics and choices

Price parameters were directly calculated from or informed by historical ERCOT price data and can be set distinctly for each hub

Correlation of normal daily price movements among locations

	North	South	West	Houston
North	100%	87%	92%	91%
South	87%	100%	86%	90%
West	92%	86%	100%	86%
Houston	91%	90%	86%	100%

Prices for nodal can be simulated using adjusted parameters

New correlation matrix

Correlation between RT and DAM expected to be very high (95% proposed)

New jump parameters for DAM

May include smaller, less frequent jumps

Jump parameters

Category	Historical ranges	Price assumptions
Frequency of jump days	4.6-5.6%	**7**-10%
Percent likelihood of a 1-, 3- , or 6-day jump series	79%, 17%, 4% respectively	75%, 20%, 5% respectively
Frequency of jumps common to multiple zones	80%	80%
Average jump size (above base price)	64-69 \$/MWh (1.2 hr / day)	~ 80 \$/MWh
99^{th} % highest expected jump (reflects price cap in desired market design)	123-147 \$/MWh (2.25 hr / day)	~ 375 \$/MWh

Exposure Module

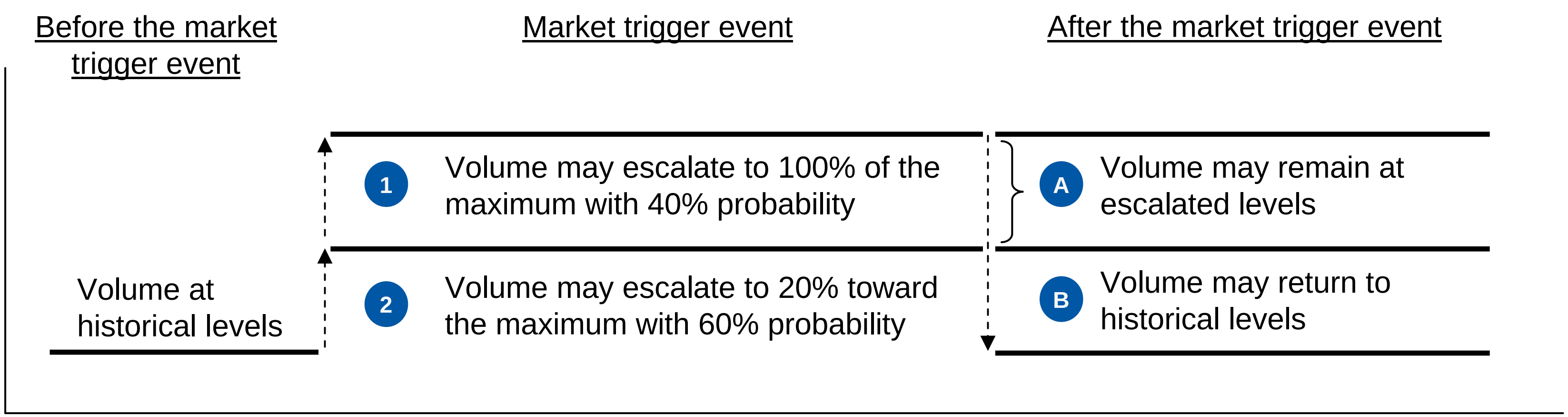
Key modeling assumptions or issues

Relationship of default to market events	▪ Market events – The model will use prices in the counterparty's primary hub (hub with the most volume) – The default is placed near a price jump event (1-,3-,6-day jump events exist) – The jump event chosen will be the longest in the price series (e.g., the model will first look for a 6-day series, but if not present the model will look for a 3-day series, etc.) ▪ Non-market events – The default is placed randomly within the time horizon of the analysis
Volume escalation potential	▪ Based on whether the default event was market-driven or not, certain volume escalation scenarios will follow to reflect the potential for increasing participation in the BES market ▪ The user can specify likelihoods of escalation levels, where escalation is based on a percent movement between historical averages and maximum volume
Default mode drives exposure period	▪ The number of days over which volumetric exposure to BES prices occur is driven by the default mode ▪ Two modes are currently considered; mass transition and bankruptcy/leaving the market

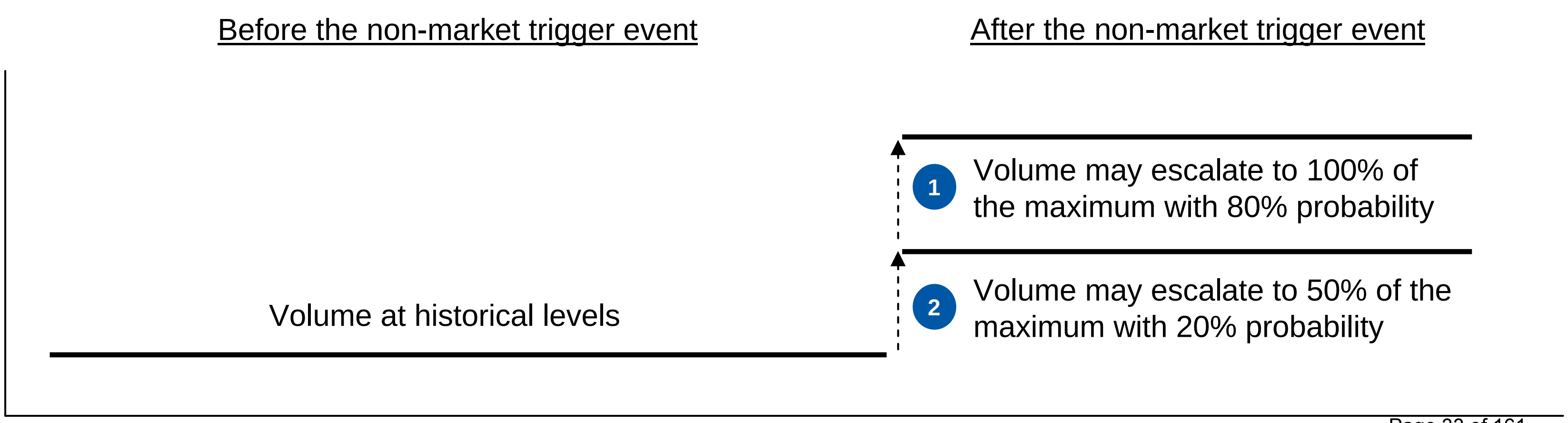
Our approach to volumetric exposure allows for a range of possible scenarios

Illustrative

Simple example 1 – Volumetric exposure during a market event for a load-serving QSE



Simple example 2 – Volumetric exposure during a non-market event for a load-serving QSE



Volume escalation assumptions

During a market event

	Red to 0	Main Hist	20%	40%	70%	100%
Generators	10%	50%	30%	9%	0%	1%
Small retailer	5%	20%	40%	10%	0%	25%
All others	0%	50%	40%	9%	0%	1%

Note: Escalations for non-market events are similar

After a market event

	Maintain at escalation	Return to historical levels	Maximum
Gen/LR/PP/Mixed	30%	70%	
Small retailer	30%		70%
Traders	0%	100%	

Collateral Module
Key modeling assumptions or issues

Simplified calculation to identify key drivers

- The calculation focuses on exposure due to price and volume
- Based on activity in BES, RT and DAM
- Excludes additional adjustments (e.g., PU, TCRs) which are not easily predictable, nor the key drivers of loss

Haircuts for collateral types

- Haircuts may be applied to different collateral types (e.g. letter of credit vs. cash)

Conceptual model of collateral adjustment

Structured to reflect ERCOT protocols

- The collateral module is designed to simulate ERCOT's collateral calculations for the current and nodal market
- Collateral requirements will be simulated for BES, RT and DAM activity
- Impacts of other billing determinants are not considered
- Collateral is required based on the higher of EAL and NLRI (or AIL for nodal)

EAL – Estimated Aggregate Liability

- Average daily transaction (ADT) calculated based on latest two invoices
- ADT extrapolated to 40 days (ADTE)
- EAL is the highest ADTE during previous 60-day period (~9 weeks)
- Estimated activity for outstanding invoices (OUT) for BES, RT and DAM will be included in the calculation
- Additional adjustments are applied, but will not be included in the model
  - TCR auction revenue
  - Potential uplift
  - Other miscellaneous invoices

NLRI – Net Load/Resource Imbalance Liability

- Accounts for invoice periods that are completed but not invoiced and invoice periods not yet completed
- For twenty-one uninvoiced days:
  - Price * estimated volume
- For seven forward-projected days:
  - (Price * 150%) * yesterday's volume

Key Stress Tests – Zonal market design

Many variations in inputs and assumptions have been examined

- Primary stress tests focused on market (price) and participant (escalation and sensitivity) behaviors
- Withdrawal of excess collateral (above ERCOT requirements) prior to default
  - This assumption directly increased net losses
  - Primarily for larger participants, whose defaults tend to drive the tails of the loss distribution
  - Greatly accentuates the impact of all other stress factors
- Ability and likelihood of defaulting participants increasing their exposure to the market toward (or to) their maximal potential (volume escalation)
  - Losses are very sensitive to this parameter choice, since the largest counterparties are orders of magnitude bigger than the smaller counterparties
  - Collateral is based on recent invoicing, thus recent activity rather than potential activity
- Higher prices and/or more, higher and longer duration price spikes
  - Alone, this stress test produced only slightly higher losses
  - In conjunction with enhanced escalation, impact increased noticeably
- Correlation of defaults with price spikes (aka, market event sensitivity)
  - Increasing this correlation increased losses in the loss distribution tails, but not in the extreme tails
  - Extreme tail losses were likely already caused by default on high price days
- Credit quality or rating of the participants
  - Increasing credit quality decreases the number of defaults in any single simulation
  - Also shifts the loss distribution down as there are more cases with no defaults
  - Loss given default is unchanged, although the multiple defaulting entity cases are diminished

Key Stress Tests – Nodal market design

Additional situations should be studied when data become available

- Nodal market design version of the credit loss model differs somewhat from the Zonal market version
  - Both RT and DAM markets can be represented
  - Price modeling at RT and DAM locations is identical to the Zonal BES market model (mean reversion, jumps, correlations, etc)
  - The spirit of the current market rules for collateral have been reflected in the model logic
  - CRR holdings can be accommodated, with valuations for the realized and unrealized portions
- The reasonableness of the overall credit loss results from this model are currently difficult to assess, because there is no firm basis for many of the required assumptions
  - Volume of participation by each counterparty in each DAM and each RT market
  - Price behavior at the DAM and RT locations
  - Number of DAM and RT locations to consider
  - Number, tenor, size and location of the CRRs held by each counterparty
  - Collateral is based on recent invoicing, thus recent activity rather than potential activity
- As data is collected, some of these parameters can be estimated
- Initial model runs can test some of the remaining assumptions, by varying those parameters
- Credit scoring and the estimation of counterparty PDs will be unchanged

DRAFT

Credit Working Group
ERCOT
Meeting Minutes
January 30, 2008

Attendance

Independent Retail Electric Providers	Jim Karculias – Cirro Energy Michael Erbrick – EPIC Merchant Energy Amanda List – Strategic Energy Pam Carr – Stream Gas & Electric Ltd Donald Meek – Green Mountain Energy Company Amy Archambault – Tara Energy
Independent Power Marketers	Tanya Rohauer – Reliant Energy Kyle Gionis – Keystone Energy Robert Alsbrooks – Tenaska Power Services Phil Priolo – Exelon Generation Company
Independent Generators	Becky Kilbourne – North American Energy Credit & Clearing Morgan Davies – Calpine Nithya Venkatesan – NRG Jane Wilhite – SUEZ Energy North America Inc
Investor Owned Utilities	Lisa Groff – AEP Corporation Laura Seeberg – AEP Corporation Timothy Coffing – TXU Portfolio Management
Municipals	Josephine Wan – Austin Energy Lee Starr – Bryan Texas Utilities (BTU) Robert Miller – San Antonio City Public Service Domingo Villarreal – San Antonio City Public Service
Cooperatives	Khaki Bordovsky – Brazos Electric Power Cooperative Sridhar Pushpavanam – Lower Colorado River Authority Richard Ramirez – Lower Colorado River Authority
Others	Jonathan Griffin – PUC Clayton Greer – J Aron Eddie Kolodzies – Customized energy Solutions Seth Cochran – Sempra Energy Trading Edward Smith – Oliver Wyman Michael Denton – Oliver Wyman
ERCOT Staff	Cheryl Yager Vanessa Spells Chad Seely Srini Sundhararajan Rizaldy Zapanta

Amanda List called the meeting to order at 9:30 am.

Approval of Minutes of November 29, 2007 and December 18, 2007

Nithya Venkatesan submitted a motion to approve the November 29, 2007 and December 18, 2007 Minutes. Tim Coffing seconded the motion. Motion passed.

Review NPRRs

The group reviewed the following NPRRs for credit implications:

NPRR 096 Revisions to the RMR Startup Energy Payment
NPRR 097 Changes to Section 8 to Incorporate Role of TRE, the IMM, and the Concept of Market Compliance
NPRR 098 Protocol Sections 4 and 6 Formula Clarifications and Related Revisions
NPRR 099 RMR Incentive Factor Payment
NPRR 100 PCRR Release Mechanism

Mr. Coffing submitted a motion that there are no credit implications on the above NPRRs. Ms. List seconded the motion. Motion passed.

OW Preliminary Results

Cheryl Yager provided CWG members a brief recap of the background leading up to the OW study as well as a review of the preliminary results of the Oliver Wyman project. Ms. Yager specifically discussed the following key points:

1. The assumptions used, while kept as broad as possible, do not take into consideration every possible scenario in light of the need for processing efficiency within the model. The following assumptions were revised based on discussions in the November 2, 2007 meeting:
   a) volume escalation probabilities in the BES market were adjusted to reflect a broader range of possibilities;
   b) average size of price jumps was reduced from $120 to $80 /mwh; and
   c) for load serving entities, the correlation between defaults and price spikes was changed to 50%

2. Of the 100 QSEs that were included in the credit loss study, 23 were evaluated as investment grade, 38 were evaluated in the BB range (between BB- and BB+), 23 were evaluated in the B range (between B- and B+) and 16 were included at the default rating of CCC+. The above ratings were after application of group logic, when appropriate, to an initial rating for each QSE.

3. The model generated a range of potential losses at specific confidence levels over a one year timeframe and with a given set of assumptions. Two scenarios were run: a) a baseline scenario which reflects market and behavioral assumptions assuming collateral is held based on Protocol requirements only and b) a comparison scenario which uses identical assumptions except that actual collateral held at a specific point in time is recognized. The maximum loss at the 99.9% confidence interval is expected to be $99.8 million under the baseline scenario and $29.8 million under the comparison scenario. Ms. Yager emphasized that the maximum loss number that must be considered increases with increase in the confidence percentile.

CWG members raised the following points/issues:

1. Ms. Rohauer noted that, in the credit scoring model, the 30% weighting assigned to working capital/sales ratio seems high and/or that a different metric should be used. Ms. Yager explained that OW determined that this ratio provided a good measure of liquidity given the data limitations (e.g. data needed for other measures of liquidity were not available for all QSEs) and the time constraints of the project. The heavy weighting was due to the importance placed on liquidity. She pointed out that the model can accommodate other measures of liquidity once data is available and that the model provides flexibility through the use of qualitative factors or adjustments to compensate for concerns about specific quantitative factor.
2. On OW's note that a 99% confidence interval was a common practice among financial institutions to evaluate credit quality, Ms. Rohauer commented that using financial institution standards was not appropriate for ERCOT. Ms. Rohauer suggested that a 95% confidence interval is more commonly used within individual energy companies for evaluating credit risk and therefore may be more appropriate to be used for credit risk in the ERCOT market as a whole.
3. Ms. Rohauer also requested a list of the OW criteria used to establish implied support for "group logic."
4. Cheryl Yager informed CWG members that the credit scores the model yielded were specifically to be used in the PFE model and not incorporated in the protocols or Creditworthiness Standards for determining credit lines.

5. Ms. Wilhite commented on the methodology that Oliver Wyman has adopted with respect to guaranties in the model. Ms. Wilhite noted that it is standard industry practice, in both the bilateral and ISO marketplace, to rate a guaranteed entity the same credit rating as its' guarantor. The Oliver Wyman model uses a blended scoring methodology consisting of both the guarantor's credit quality and the guaranteed entities stand alone credit quality. Given that guaranteed entities do not produce/publish financials, a worst case scenario is presumed which will portray a less creditworthy view of the ERCOT market participants.

Discussion on Market Participant (MP) Guarantee Agreement

Chad Seely informed CWG that ERCOT Legal received a proposed redline version of the MP Guarantee Agreement from its outside counsel. Currently, ERCOT Legal is reviewing the redline version for applicability to the ERCOT market. Mr. Seely briefly discussed proposed revisions and informed CWG members that a redline draft will be distributed in early February. Mr. Seely suggested that CWG members provide comments on the distributed redline version and, if need be, create a CWG Sub-Group to address any proposed revisions to the MP Guarantee Agreement.

LaaRs Negative Bid Issue

Mary Ann Brelinksy of DSWG provided a brief overview and background of the LaaR bidding history and issues as well as the solutions/measures that were adopted to address the issues. Ms. Brelinsky said that the DSWG believes there are two potential options to correct the issue for day one of the Nodal market: 1) implement a floor price until a market based solution is agreed upon by stakeholders and 2) modify credit requirements/calculations to cover exposure arising from negative LaaR bids and asked CWG for their input on an appropriate short term solution. Srini Sundhararajan, however, explained that to enable ERCOT Credit to estimate exposure arising from negative bids, a system modification on the Market Management System (MMS) and not on the Credit Monitoring & Management (CMM) system will be required. Given time constraints for the Nodal go-live date, CWG members agreed that option no. 2 would therefore not be feasible. CWG members also agreed to consult their respective operations people regarding the issue. The short and long-term solutions would be discussed at the next CWG meeting.

New Business

Ms. List proposed that monthly face-to-face meetings maybe necessary to discuss the Oliver Wyman results as well as the Guarantee Agreement revisions.

She suggested having the first meetings in Houston given that many CWG members have offices there. Morgan Davies offered to host the first meeting at Calpine's Houston office. CWG members agreed to hold the meeting on Friday, March 7. Meanwhile, a conference call will be held on February 21 at 3:00 pm to discuss the LaaRs negative bid issue and other topics.

The meeting was adjourned at 2 pm.

DRAFT

Credit Working Group
ERCOT
Meeting Minutes
March 7, 2008

Attendance

Independent Retail Electric Providers	Amanda List – Strategic Energy Peter J. Karculias – Cirro Energy Pam Carr – Stream Gas & Electric Ltd Kyla Douglas – EPIC Merchant Energy Michael Erbrick – EPIC Merchant Energy Margaret Munnelly - Tara Energy Patrick Meyers – Tara Energy Mandy Gregg - ACES
Independent Power Marketers	Tanya Rohauer – Reliant Energy Kelly Minear – BP Energy Mary Fantozzi – Citigroup Jason Gower – Constellation Energy Elizabeth Ramirez – Coral Energy Shivi Punia – Direct Energy Robert Alsbrooks – Tenaska Power Services Phil Priolo – Exelon Generation Company
Independent Generators	Morgan Davies – Calpine Jane Wilhite – SUEZ Energy North America Inc Nithya Venkatesan – NRG
Investor Owned Utilities	Timothy Coffing – TXU Portfolio Management
Municipals	Tamila Nikazm – Austin Energy Josephine Wan – Austin Energy Lee Starr – Bryan Texas Utilities (BTU) Domingo Villarreal – San Antonio City Public Service
Cooperatives	Khaki Bordovsky – Brazos Electric Power Cooperative Brady Edwards – Lower Colorado River Authority Richard Ramirez – Lower Colorado River Authority
Others	Clayton Greer – J. Aron & Company Craig Bricker Patty Harrold
ERCOT Staff	Cheryl Yager Vanessa Spells Chad Seely Rizaldy Zapanta

Amanda List called the meeting to order at 9:15 am.

Ethics Training

Chad Seely conducted an Ethics Training for all CWG members in attendance both in person and by phone during the meeting.

Approval of Minutes of January 10, 2008, January 30, 2008 and February 21, 2008

Nithya Venkatesan submitted a motion to approve the January 10, 2008 Minutes. Brady Edwards seconded the motion. Motion passed.

Tanya Rohauer submitted a motion to approve the February 21, 2008 Minutes. Brady Edwards seconded the motion. Motion passed.

On the January 30, 2008 minutes, CWG members agreed to defer approval pending inclusion of additional comments on the Oliver Wyman (OW) Preliminary Results presentation.

Jane Wilhite asked to include her comments that OW's use of a blended scoring methodology presumes a worst case scenario for guaranteed entities that do not provide financials and therefore will portray a less creditworthy view of ERCOT market participants.

Ms. Rohauer also proposed including the following comments and notation on the OW presentation that:

1. Ms. Rohauer believed that using a standard of a 99% confidence interval, while a common practice among financial institutions to evaluate credit quality, was not appropriate for ERCOT.
2. Cheryl Yager informed CWG members the credit scores the model yielded were specifically to be used in the PFE model and not incorporated in the Protocols or Creditworthiness Standards for determining credit lines.
3. A list of the OW criteria used to establish implied support for "group logic" would be provided to CWG members.

PRRs/NPRRs

NPRR 101 Modify Time Requirements for Entry of Equipment in the Outage Scheduler

NPRR 102 Implementation of PUC SUBST. R. 25.505(f), Publication of Resource and Load Information

NPRR 103 Settlement of Power Imported via DC Ties and Block Load Transfer Under a Declared Emergency Condition

Mr. Edwards submitted a motion that there are no credit implications on the above NPRRs. Ms. Wilhite seconded the motion. Motion passed.

Review Credit Scoring Model

Ms. Yager reviewed the approach currently used for generating PD estimates for the capital adequacy model noting that

1) unrated subsidiaries of rated parents are scored somewhere between their base rating (or CCC+ if no financials are available) and their parent's rating after group logic factors are applied
2) guarantees are included as collateral,
3)

the scoring model was used for 30 - 40 entities that were not rated and that the model will be used for more entities as the Nodal market "goes live" and as ERCOT enforces this requirement going forward.

Ms. Wilhite commented that, when an entity has a guarantee in place, she does not agree with the concept of giving a subsidiary a rating between its base rating (or CCC+ if financials are not available) and its parent rating after application of group logic . She instead proposed that entities that had guarantees should be assigned the rating of their guarantor. Morgan Davies suggested conducting a straw poll to determine how the rest of the group stands on this issue. Results of the straw poll showed that most CWG members present agreed with Ms. Wilhite's proposal. Ms. Yager questioned how to treat entities where the guarantee did not fully cover the exposure. Ms. Rohauer agreed this could be problematic and suggested that the model could be adapted to address this concern, possibly allowing the exposure to be "split' in some way to reflect the risk. Ms. Yager also noted that guarantees are cancellable with 30 days notice and / or the value can be changed dramatically. She expressed concern that this would cause the model results to be misleading. Ms. Rohauer suggested doing ad hoc runs of the model in between scheduled runs when there are material changes in the risk parameters.

Ms. Yager then reviewed the current quantitative and qualitative factors used in the Credit Scoring model, reminding the group that some of the quantitative factors selected for the analysis, given the timeframe for the project, were chosen based on the financial information available at the time. She noted that the results were reviewed by both ERCOT credit staff and Oliver Wyman staff and that both were comfortable that the overall analysis was reasonable. However, given that financial information for the fiscal year end 2007 will be available shortly and should be more complete, she asked whether there were any proposed changes to the scoring model that the group would like to consider.

Ms. Rohauer and Phil Priolo suggested including another liquidity or cash flow metric in addition to the working capital/sales metric. CWG members agreed to reduce the weight assigned to working capital/sales from 30% to 15% and include cashflow from operations / sales as a quantitative factor with a weight of 15%.

For qualitative factors, Ms. Rohauer suggested reducing the weight of late payment history from 20% and increase the weight of risk management policies and practices from 10%. Ms. Rohauer explained that payment history is not always truly indicative of probability of default. After discussion, the group agreed to reduce the weight for late payment history from 20% to 15% and increase the weight of risk management policies and practices from 10% to 15%.

Ms. Yager noted that it would be May or June (once year end financials were in) before ERCOT could test the proposed changes. Ms. Rohauer requested that sample financials be provided to the group along with the rating assigned by the model for the group to review. Ms. Spells agreed to provide indicative financials.

Risk Appetite Statement

Ms. List informed CWG members that the F&A Committee had asked the CWG to develop a risk appetite statement for the Committee's and the BOD's consideration. This was requested because of the F&A Committee's consideration of an OW recommendation that it was best practice to adopt a formal risk appetite statement. F&A also asked that ERCOT staff seek input from TAC and the PUCT. TAC has asked CWG to work closely with its WMS and RMS subgroups on this matter.

CWG members provided the following comments:

1. Nithya Venkatesan asked what OW's basis was for saying that a risk appetite statement is a best practice and asked whether other ISOs have adopted a similar statement. She also inquired about what the BOD might require if a risk appetite level is exceeded. Ms. Yager explained that a risk appetite statement would provide the BOD a parameter against which the overall risk in the market could be evaluated and eventually aid in formulating comprehensive credit risk mitigation measures instead of

pursuing piece-meal approaches. She indicated that she did not think other ISO's had a formal risk appetite statement at this time.

2. Clayton Greer commented that in formulating a risk appetite statement, there is a risk of making too broad of a policy statement. He expressed concern that, since the parameters underlying measurement of risk are rough, basing a policy statement on them may be premature.
3. Ms. Rohauer commented that it could be very difficult for the CWG to formulate a risk appetite statement given that CWG members have widely different views on the matter, noting that CWG members come from various companies that may very well have different risk appetites.
4. Kyla Douglas asked whether the formulation of a risk appetite statement was a first step that the BOD thinks would be necessary in coming up with an enterprise risk management philosophy. Ms. Yager replied that it could very well be, but it is something that the BOD had not discussed as of yet.
5. Given that OW raised the need for a risk appetite statement, Ms. Rohauer suggested asking OW to provide samples of such statements.
6. Mr. Davies suggested first running a PFE for the market for a base case and a stress case for CWG members to better understand the factors that impact the model. Ms. Rohauer also suggested that as part of developing a statement, the CWG would need to agree on the assumptions / scenarios that would be used in the model.

Given all the comments and concerns above, Ms. List and Ms. Yager said that additional face-to-face meetings will be necessary to work through the details. Ms. List asked members to keep in mind that the BOD wants a proposal from the CWG by its May 20th meeting and that any proposal would also have to be worked through TAC. CWG members agreed on having a meeting on Thursday, April 3rd and another on either Wednesday, April 23rd, or Thursday, April 24th.

Ms. Rohauer asked that the agenda for the next meetings be as robust and flexible as possible to maximize the benefit of thee time CWG members put in.

Acceptance of Guarantees and Financial Statements from Parent Companies Not Meeting ERCOT Creditworthiness Standards

Ms. Yager informed CWG members that some QSEs that have not historically had audited financial statements have asked if ERCOT would be willing to accept guarantees from their parent companies even if these do not meet ERCOT's creditworthiness standards. This would allow the market participants to provide their parent companies' financial statements and comply with protocol requirements.

Ms. Yager explained that historically ERCOT has not accepted guarantees from parent companies which do not meet ERCOT creditworthiness standards. CWG members were asked whether they had any concerns about accepting guarantees in these circumstances, understanding that no unsecured credit would be granted. She added that ERCOT staff would retain the right to ensure that the guarantee added value for the market or they would not accept the guarantee. No CWG member indicated that they had a problem with accepting guarantees for this purpose.

CRR Weighting Factors

Ms. Yager explained that forward mark-to-market exposure valuation of CRRs is based on historical pricing and that the Nodal protocols have provided that weights be applied on the different prices to be used. CWG must decide on the weights to be assigned before the Nodal market goes live. Ms. Yager clarified that while historical pricing is not the best way to value mark-to-market exposure, it is currently the only option available since there is not a robust forward market or predictive pricing. Once data is available after the CRR market opens, a better pricing methodology for forward risk may be considered. Ms. Yager said that the CWG would eventually need to conduct a vote on weighting factors to use.

Mr. Greer commented that using historical pricing in estimating mark-to-market exposure is not adequate to measure forward risk, particularly in a dynamic market. He suggested that CWG look into developing some form of forward price analysis to come up with a better measure of forward risk. Ms. Yager replied that currently ERCOT does not have the system capability or personnel resources to attempt predictive pricing and that this will likely only be possible after the CRR market has operated for a while.

The meeting was adjourned at 3:00 pm.

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ERCOT CORPORATE STANDARD

Document Name: Market Credit Risk Standard
Document ID: _________
Effective Date: Upon Approval
Owner: Board of Directors, F&A Committee
Approved:

1.0 PURPOSE

This Market Credit Risk Standard provides a framework by which the ERCOT Board of Directors seeks to maintain the long-term financial integrity of the ERCOT market and to help ensure that overall market credit risk is maintained within acceptable limits.

2.0 DEFINITIONS

Base Case – the Potential Credit Risk Model scenario that considers only forms and amounts of collateral required per ERCOT Protocols.

BOD – Board of Directors

Current Case – the Potential Credit Risk Model scenario that considers forms and amounts of collateral held as of a specific point in time. This scenario may include collateral amounts above those required per ERCOT Protocols and which can be unilaterally withdrawn at the Counter-Party's direction.

CWG – Credit Work Group

Expected Loss – the average – although not the most common – outcome across all outcomes It represents the loss the market as a whole should expect to incur over time under given market conditions as a result of its portfolio credit risk.

Loss Distribution – a range of potential losses under a specific set of parameters with a given probability of occurrence

Potential Credit Risk (PCR) Model – the financial model that ERCOT uses to measure potential credit risk It is constructed using a standard Potential Future

Exposure framework that produces a portfolio Loss Distribution of potential losses.

Potential Credit Risk (PCR) Report – a report that provides the results from the PCR Model together with ERCOT staff's analysis

Potential Future Exposure (PFE) – an estimate of potential credit risk resulting from existing counterparty relationships in light of possible future risk factors such as price volatility and volume escalation.

Probability of Default (PD) – a Counter-Party specific measurement of the likelihood that that Counter-Party will default over a specified time horizon

TAC – Technical Advisory Committee

3.0 STANDARD

Market Credit Risk Objective
In seeking to fulfill BOD objectives to provide for a reliable Texas electricity market ERCOT stakeholders will

- directly consider the credit implications of operational or market decisions, and
- seek to maintain a market-wide credit risk profile consistent with an investment grade rating

Market credit risk, as measured by the PCR Model, should not exceed:

1) $______________ at a ___% confidence level under the Base Case scenario, and

2) $______________ at a ___% confidence level under the Current Case scenario.

If at the time of any model run the market credit risk exceeds either of the above limits or if ERCOT identifies credit risks that may require immediate action,

1) ERCOT staff will:
   a. Provide an ad hoc PCR Report within 3 business days of completing their analysis to the Chairmen of the F&A Committee, TAC and CWG, which includes an analysis of the cause(s) of the higher risk,
   b. Provide a recommendation as to whether immediate action is needed,

c. If immediate action is recommended, provide a proposed plan to bring credit risk within approved parameters within 30 days, and
d. With BOD approval, take actions allowed in the Protocols to bring credit risk within approved parameters within 30 days of receiving that approval.

2) The BOD will:
   a. Review the cause(s) of the higher risk and ERCOT staff's recommendations,
   b. Determine any short-term actions to be taken, and
   c. Determine the timeframe for any required TAC actions.

3) TAC, in consultation with the CWG, will develop and execute a plan to bring credit risk within approved parameters within the timeframe required by the BOD.

Delegation of Authority
Responsibility for monitoring and reporting on credit risk for the market consistent with this standard is hereby delegated to the Chief Executive Officer, the Chief Financial Officer and the Treasurer. These individuals willl ensure the BOD is advised of credit risk matters consistent with the parameters specified herein.

Internal Control
The Treasurer will ensure that written procedures and internal controls are established over the portfolio credit risk analysis process to ensure that results are consistent with the approved process.

The Treasurer will ensure that these controls are reviewed periodically by ERCOT's Internal Audit staff to test compliance with procedures.

In addition, the Treasurer will obtain an independent review of the PCR model within one year of Nodal market implementation and at least biennially thereafter.

Measurement
ERCOT staff will use a standard Potential Future Exposure framework for measuring credit risk. The PCR Model, which was built on this framework, will be maintained within this framework.

At a minimum, ERCOT's portfolio credit risk analysis will include the following risk factors:

- Probability of Default for each QSE (resulting from credit score or rating),
- Forward price analysis,

- Price volatility analysis,
- Volume escalation behavior analysis, and
- Simplified collateral calculations.

ERCOT staff will update these risk factors, as well as the related data inputs defined in Appendix A, as needed when key risk factors change.

ERCOT will use the assumptions defined in Appendix B for the Base Case and Current Case scenarios and will update model assumptions periodically with CWG input.

ERCOT will run stress scenarios beyond the Base Case and Current Case using more extreme assumptions that seek to quantify the credit risk around such things as market price events, high correlations of default, impacts of specific types of market activities and high concentration of exposures to Counter-Parties or types of Counter-Parties.

Although it is impractical to model all possible loss scenarios within the PCR Model, the PCR Model is a valuable tool to more effectively manage credit risk within the ERCOT market. The model considers identified risk factors and provides an indication of potential losses; however, actual losses may be more or less than those indicated by the model.

Reporting

ERCOT staff will maintain and run the PCR Model and will prepare an analysis:

1. at least quarterly,
2. whenever ERCOT staff determines there have been changes in credit risk factors warranting a model run, and
3. upon request of TAC or CWG when contemplating market rule changes for which credit implications are being evaluated.

The PCR Report will, at a minimum, include:

1. the Base Case and Current Case scenarios,
2. Expected Loss, median loss and Loss Distribution at the 90, 95, 99, 99.9th percentile for required and ad hoc scenarios,
3. For additional scenarios provided, a listing of inputs used (specific, where possible; general when inputs are Counter-Party specific), and
4. ERCOT staff's analysis of the reasons for significant changes in credit risk from the prior PCR Report.

A summary of the PCR Report will be provided to the Finance and Audit committee, TAC and the CWG at least quarterly.

If limits are exceeded, ERCOT staff will also report on ERCOT and market efforts to bring credit exposure within required limits.

Market Credit Risk Standard Adoption.
ERCOT's Market Credit Risk Standard will be adopted by resolution of the Board of Directors. The standard will be reviewed annually by the Finance and Audit Committee and any modifications made thereto must be approved by the Board of Directors.

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Appendix A

Model Inputs

Global Inputs
- Time horizon (in days)
- Number of simulations
- Number of hubs / zones
- Number of Counter-Parties

Default inputs
- Probability of Default of each QSE
- Default correlation types
- Market event sensitivity types

Exposure inputs
- Settlement & billing cycle
- Volume escalation behavior
- Maximum potential volume
- Length of time of mass transition (if applicable)

Price inputs
- Forward prices predicted from forward gas prices, based on local spark spreads
- Price movement correlation between zones
- Frequency and size of jumps
- Jump event types (1-, 3-, 6-day jump series)
- Frequency of jumps common to multiple zones
- Locational differences that drive CRR pricing

Collateral inputs
- Number of days to post collateral and cure a breach
- Simplified collateral calculations
- Collateral haircut

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Appendix B

To be completed

Electric Reliability Council of Texas
Summary of Investment Results
First Quarter 2008
(in 000's)

Return for the quarter ended March 31, 2008	Balance at March 31	Average Bal for Qtr	Interest 1st Qtr	Yield 1st Qtr	% of portfolio at March 31
Reserve Prime Fund (Operating and Mkt) (Note 1)	64,702	65,982	695.0	4.22%	31.3%
Reserve US Gov Fund (Deposits/Restricted) (Note 2)	140,025	145,523	1,252.8	3.45%	67.8%
Other cash net of outstanding checks	1,785				0.9%
Total cash and cash equivalents (est)	206,512	211,505	1,947.8	3.69%	100.0%

		Benchmark Information	
Benchmark data	ERCOT Yield	Ranking iMoneyNet	Top Funds within category
	(Notes 4, 5)	(Note 4)	(Note 4)
Reserve Prime Fund (Operating and Mkt) (Note 1)	3.50%	1 out of 14	Range 3.50% to 3.30%
Reserve US Gov Fund (Note 2)	2.59%	Not in top 19	Range 2.86% to 2.65%

Note 1: The Reserve Prime fund includes commercial paper and other high grade, short term corporate notes, CD's, time deposits and other short term money market instruments that meet the SEC requirements to be included in a MMF.

Note 2: The Reserve US Governmental Fund includes Treasuries and other governmental securities.

Note 3: No individual securities held at March 31, 2008.

Note 4: As of April 1, 2008 based on 7-day yield.

Note 5: The Federal Reserve lowered the borrowing rate to banks by 75 basis points on January 22, 50 basis points on January 30, and 75 basis points on March 18, 2008, respectively.

Statement of Compliance

Upon a review of the investment activity for the 3 month period ended March 31, 2008, I have no knowledge of any activity that does not comply with the Investment Standard.

Signature on File
Cheryl Yager, Treasurer

Signature on File
Steve Byone, Chief Financial Officer

PRRs/NPRRs

4/25/08

PRRs

- 753: PRR Appeals Process
- 756: Distributed Renewable Generation Modifications
- 757: Emergency Interruptible Load Service Formula Correction
- 760: Emergency Interruptible Load Service (EILS) Availability Factor

NPRRs

- 105: Section 23, Synchronization of Zonal Protocols
- 106: Section 24, Synchronization of Zonal Protocols
- 108: Fuel Oil Price (FOP) Clarifications
- 109: Section 18, Synchronization of Zonal Protocols
- 110: Section 20, Synchronization of Zonal Protocols
- 112: Emergency Base Point Price Revision
- 113: Load Resource Type Indicator for Ancillary Service (AS) Trades and Self-Arranged AS

Protocol Revision Request

PRR Number	753	PRR Title	PRR Appeals Process
Date Posted		February 4, 2008	

Protocol Section(s) Requiring Revision (Include Section No. and Title)	21.4.11, Appeal of Decision
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal
Revision Description	This Protocol Revision Request (PRR) provides for a more structured process for parties to appeal the decisions pertaining to PRRs made by the Protocol Revision Subcommittee (PRS) and the Technical Advisory Committee (TAC). This proposal also provides timelines for appealing PRS and TAC decisions and makes accommodating provisions for PRRs on an Urgent timeline.
Reason for Revision	The ERCOT Board of Directors (Board) requested that TAC develop a more structured process for presenting appeals to the Board.
Overall Market Benefit	A structured and transparent appeals process creates predictability for all parties and ensures due process.
Overall Market Impact	None
Consumer Impact	None
Credit Implications	None
Relevance to Nodal Market	These provisions may need to be incorporated in Section 21.11.3.10, Appeal of Decision, for Nodal PRRs (NPRRs) appealed under the zonal ERCOT Protocols, as well as any future Nodal Protocol Sections that address the appeals process.
Nodal Protocol Section(s) Requiring Revision (Include Section No. and Title, and submit NPRR if applicable)	Nodal Protocol Sections addressing the appeals process have not been developed yet.

Quantitative Impacts and Benefits

Assumptions	1		
	2		
	3		
	4		
~~**Market Cost**~~		**Impact Area**	**Monetary Impact**

Protocol Revision Request

	1	*No costs to Market Participants are anticipated.*	*No costs to Market Participants are anticipated.*
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*No quantifiable impacts are anticipated.*	*No quantifiable monetary impacts are anticipated.*
	2		
	3		
	4		
Additional Qualitative Information	1	*Structured and transparent processes create predictability and benefit all Market Participants.*	
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

Sponsor	
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Market Segment	n/a

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Protocol Revision Request

Proposed Protocol Language Revision

21.4.11 Appeal of Decision

21.4.11.1 Appeal of PRS Action

If PRS rejects the PRR, any ERCOT Member, Market Participant, ~~the~~ PUCT Staff or ERCOT Staff may appeal directly to the TAC. Such appeal to the TAC must be submitted to ERCOT's General Counsel and the TAC Chair within ten (10) Business Days after the date of the relevant PRS action~~decision~~. ERCOT shall reject a~~A~~ppeals made after that~~is~~ time~~ shall be rejected~~. ERCOT shall post the appeal on the ERCOT web page dedicated to the TAC and the specific PRR within three (3) Business Days of receiving the appeal. If the appeal is submitted to ERCOT at least eleven (11) days before the next regularly scheduled TAC meeting, ERCOT shall ~~Appeals to the TAC shall be posted on the MIS within three (3) Business Days and~~ place~~d~~ ~~on~~ the appeal on the agenda ~~o~~for the next ~~available~~ regularly scheduled TAC meeting. If the appeal is submitted to ERCOT less than eleven (11) days before the next regularly scheduled TAC meeting~~, provided that the appeal is provided to ERCOT at least eleven (11) days in advance of the TAC meeting; otherwise~~, the TAC will hear the appeal ~~will be heard by the TAC~~ at ~~the~~ its next ~~next~~subsequent regularly scheduled ~~TAC~~ meeting.

21.4.11.2 Appeal of TAC Action

(1) ~~If TAC rejects the PRR, a~~Any ERCOT Member, Market Participant, ~~the~~ PUCT Staff or ERCOT Staff may appeal directly to the ~~ERCOT~~ Board any TAC ~~the~~ action ~~of the TAC~~ regarding a PRR. Upon appeal of a TAC action on a PRR, the TAC Chair shall designate a representative ("TAC Advocate") to support the TAC action. The TAC Advocate shall coordinate with any ERCOT Member, Market Participant, PUCT Staff or ERCOT Staff supporting the TAC action, as necessary, to provide relevant information to the Board. The Board will not consider any data, information or arguments not included in a timely-submitted position statement as described in item (5) of Section -21.4.11.2.1, Appeal of TAC Action – Normal Timeline.

(2) The Board Chair shall determine the total time designated on the Board agenda for the appeal with time evenly allocated between those appealing and advocating the TAC action. Questions from Board members shall not diminish a party's time allocation. The Board shall also provide notice of other Board~~?~~ meetings where the appeal may be discussed.

21.4.11.2.1 Appeal of TAC Action – Normal Timeline

An appeal submitted to ERCOT more than eleven (11) days before the next regularly scheduled Board meeting shall be considered on the following timeline (unless the appealing party requests expedited treatment of an appeal as described in 21.4.11.2.2, Appeal of TAC Action – Expedited Timeline:

(a) The ~~Such~~ appeal of the TAC action ~~to the ERCOT Board~~ must be submitted to ERCOT's General Counsel and the TAC Chair within ten (10) Business Days after the date of the relevant TAC~~decision~~ action. ERCOT shall reject a~~A~~ppeals made after that~~is~~ time ~~shall be rejected~~.

(b) Within two (2) days of receiving notice of an appeal, the TAC Chair shall appoint the TAC Advocate and provide to ERCOT's General Counsel the TAC Advocate's name and contact information.

(c) Within three (3) Business Days of receiving notice of an appeal of a TAC action, ERCOT shall post the appeal on the ERCOT web page dedicated to the Board and the specific PRR, and shall provide Notice of the appeal to the TAC.

(d) ERCOT shall, within two (2) Business Days of the date on which the TAC Chair supplies the TAC Advocate's name and contact information to ERCOT's General Counsel:

(i) Post on its web page dedicated to the Board, the name and contact information of the TAC Advocate, and

(ii) Provide that information to the TAC.

(e) No less than twelve (12) days before the scheduled date of the Board meeting in which the appeal will be heard, the appealing party, the TAC Advocate and any other interested party shall provide to ERCOT's General Counsel a position statement ("Position Statement") for distribution to the Board.

(~~6~~f) ERCOT will distribute all timely-submitted Position Statements to the Board in accordance with ERCOT's procedures for providing meeting materials to Board members.~~Appeals to the ERCOT Board shall be posted on the MIS within three (3) Business Days and placed on the agenda of the next available regularly scheduled ERCOT Board meeting, provided that the appeal is provided to the ERCOT General Counsel at least eleven (11) days in advance of the Board meeting; otherwise the appeal will be heard by the Board at the next regularly scheduled Board meeting~~

21.4.11.2.2 Appeal of TAC Action – Expedited Timeline

(1) If an appeal is submitted to ERCOT eleven (11) or fewer days before the next regularly scheduled Board meeting, the Board will consider the appeal at its next subsequent, regularly scheduled meeting and the timelines set forth above in Section 21.4.11.2.1 Appeal of TAC Action – Normal Timeline, shall apply, unless the appeal meets the criteria set forth in item (2).~~:~~

(2) Appeals that meet either of the following criteria shall be processed on an expedited basis:

(a) The appealing party requests an expedited appeal; or

(b) The PRR has Urgent status as defined in Section 21.5, Urgent Requests.~~;~~

(3) For an expedited appeal, the following timeline shall apply:

(a) The appeal of a TAC action to the Board must be submitted to ERCOT's General Counsel and the TAC Chair by Noon of the next Business Day after the date of the relevant TAC action. ERCOT shall place appeals made after that time on a "normal" timeline as set forth in Section 21.4.11.2.1 Appeal of TAC Action – Normal Timeline~~above~~.

(b) The TAC Chair shall designate a TAC Advocate and provide to ERCOT's General Counsel the TAC Advocate's name and contact information by 5:00 P.M. Central Prevailing Time of the next Business Day after the date of the relevant TAC action.

(c) ERCOT shall post on its web page dedicated to the Board the name and contact information of the TAC Advocate and shall provide that information to the TAC within one (1) Business Day of the date on which the TAC Chair supplies to ERCOT's General Counsel the TAC Advocate's name and contact information.

(d) Within one (1) Business Day of receiving notice of an appeal of a TAC action, ERCOT shall post the appeal on the ERCOT web page dedicated to the Board and the specific PRR, and provide Notice of the appeal to the TAC.

(e) No less than five (5) days before the scheduled date for the Board meeting where the appeal will be heard, the appealing party, the TAC Advocate and any other interested party shall provide to ERCOT's General Counsel any Position Statement for distribution to the Board.

(f) ERCOT will distribute all timely-submitted Position Statements to the Board two (2) Business Days before the scheduled date for the next regularly scheduled Board meeting.

(g) When the Board considers an appeal of a TAC action on a PRR, the Board may take one of the actions set forth in Section 21.4.9, ERCOT Board Vote, or postpone consideration of the PRR until a subsequent regularly scheduled meeting.

21.4.11.3 Appeal of Board Action

Any ERCOT Member, Market Participant or PUCT Staff may appeal any decision of the ~~ERCOT~~ Board regarding the PRR to the PUCT or other Governmental Authority. Such appeal to the PUCT or other Governmental Authority must be made within thirty-five (35) days of the date of the relevant decision. If the PUCT or other Governmental Authority rules on the PRR, ERCOT shall post the ruling on the MIS.

Protocol Revision Request

PRR Number	756	**PRR Title**	Distributed Renewable Generation Modifications
Date Posted	February 29, 2008		

Protocol Sections Requiring Revision	2.1, Definitions 2.2, Acronyms 11, Data Acquisition and Aggregation 11.4.4.2, Adjustment for Energy Exports of PV Generation Behind the Meter (new) 11.4.4.3, Adjustment for Energy Exports of Non-PV Renewable Generation Behind the Meter (new) 18, Load Profiling 18.2, Methodology 18.2.2, Load Profiles for Non-Interval Metered Loads Without Distributed Renewable Generation 18.2.3, Load Profiles for Non-Interval Metered Loads With Distributed Renewable Generation (new) 18.2.9, Adjustments and Changes to Load Profile Development
Requested Resolution	Urgent - HB 3693 "relating to energy demand, energy load, energy efficiency incentives, energy programs, and energy performance measures" requires that ERCOT implement the settlement of distributed renewable generation as of 1/1/2009. This implementation requires a new set of Load Profiles as per the TAC Distributed Generation Task Force (DGTF) recommendation #3, Settlement Solution for Small Profiled Distributed Renewable Generation. New Load Profiles require a market notice of at least 150 days prior to their implementation. To meet these timelines and the TAC request for associated proposed Protocol language revisions at their April meeting, the Urgent resolution is requested.
Revision Description	These changes allow for Load Profiling and Data Aggregation methodology to better represent output of distributed renewable generation Resources with a capacity of less than 50 kW.
Reason for Revision	To comply with HB 3693.
Overall Market Benefit	Allows for settlement of distributed renewable generation Resources with a capacity of less than 50 kW.
Overall Market Impact	Minimal until the population of renewable Resources becomes significant.
Consumer Impact	Enables settlement of renewable generation values that are not recorded on a 15 minute basis.
Credit Implications	None.
Relevance to Nodal Market	No.

Protocol Revision Request

Nodal Protocol Section(s) Requiring Revision	No.

Quantitative Impacts and Benefits			
Assumptions	1		
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1	*Data Aggregation process*	*Minimal ERCOT cost of less than $50k*
	2	*867 process*	*Project with estimated cost of $450k*
	3	*Creation of new Load Profiles for Premises with renewable generation Resources*	*Minimal ERCOT Operations and Maintenance (O&M) costs*
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Consumer*	*Allows for settlement benefit*
	2	*REP*	*Minimal settlement benefit*
	3		
	4		
Additional Qualitative Information	1	*HB 3693 compliance*	
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

Sponsor	
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Protocol Revision Request

Proposed Protocol Language Revision

2.1 Definitions

PhotoVoltaic

Of or pertaining to a material or device in which electricity is generated as a result of exposure to light.

2.2 Acronyms

PV PhotoVoltaic

11.4.4.2 Load Reduction for Excess PhotoVoltaic Generation

Adjusted Metered Load shall be reduced for excess generation from ESI IDs with PhotoVoltaic (PV) generation behind the meter where there is a meter that measures excess energy into the grid in a separate register. Only ESI IDs that have been assigned a PV profile segment as specified in Load Profiling Guide Appendix D, Profile Decision Tree, shall be eligible for this reduction.

Intervals beginning 11:00 A.M. and ending 3:00 P.M. CPT (spanning 16 15-minute intervals) shall be reduced by the following amount.

$$PV\_adjust_i = kWh\_Gen / (read\_days * 16)$$

Where:

PV_adjust_i	Reduction for PV excess generation for interval i
kWh_Gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
~~R~~read_days	Number of days in meter read period

11.4.4.3 Load Reduction for Excess Non-PhotoVoltaic Renewable Generation

Adjusted Metered Load shall be reduced for excess generation from ESI IDs with non-PV renewable generation behind the meter where there is a meter that measures excess energy into the grid in a separate register. Only ESI IDs that have been assigned a non-PV renewable distributed generation profile segment as specified in Load Profiling Guide Appendix D, Profile Decision Tree, shall be eligible for this reduction.

All intervals in the meter read period shall be reduced by the following amount.

$$\mathrm{REn\_adjust}_i = \mathrm{kWh\_gen} / \mathrm{read\_ints}$$

Where:

$\mathrm{REn\_adjust}_i$	Reduction for non-PV excess renewable generation for interval i
kWh_gen	Actual (measured) kWh flowing into the Distribution System (outflow from the Premise)
read_ints	Number of 15-minute intervals in the meter read period

18.2 Methodology

ERCOT will develop Load Profiles for both non-interval metered loads and Non-Metered Loads. A Load Profiling Methodology is the fundamental basis on which Load Profiles are created. The implementation of a Load Profiling Methodology may require statistical Sampling, engineering methods, econometric modeling, or other approaches.

The following Load Profiling methods will be used~~ for market open~~:

Type of Load	Load Profiling Methodology
~~N~~non-~~I~~interval ~~M~~metered	~~A~~adjusted ~~S~~static ~~M~~models
non-interval metered with distributed renewable generation	adjusted static models and engineering estimates
~~N~~non-~~M~~metered	~~E~~engineering ~~E~~estimates

Load Profiles will also be developed for Interval Data Recorders (IDRs) for use in settlements when actual IDR data is not available. All Load Profiles will conform to the ERCOT-defined Settlement Interval length.

~~Any change from one ~~Adoption of a new methodology~~ to another will~~ requires approval of TAC, without the necessity of complying with the procedures in Section 21, Process for Protocols Revision. TAC shall establish the implementation date for approved changes, as TAC deems appropriate, recognizing the magnitude of the impacts on Market Participants.

18.2.2 Load Profiles For Non-Interval Metered Loads Without Distributed Renewable Generation

Load Profiles for non-interval metered loads will be created using statistical models developed from appropriate load research sample data. These models are referred to as “adjusted static.” These model equations will relate daily Settlement Interval load patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times will also be employed.

[PRR478: Replace Section 18.2.2 above with the following upon system implementation:]

For market open, Load Profiles for non-interval metered loads were created using statistical models developed from appropriate load research sample data. These models are referred to as "adjusted static." These model equations relate daily Settlement Interval Load patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times are also employed.

Following market open, new Load Profile segments may be introduced. After these Load Profile segments receive final approval under the provisions of the Load Profiling Guides, Section 12, Request for Profile Segment Changes, Additions, or Removals, they may be settled by using appropriately sized and representative lagged dynamic samples or adjusted static models. The decision to use a lagged dynamic sample or adjusted static model shall be based on the judgment of ERCOT's Load Profiling Department, subject to TAC approval.

18.2.3 Load Profiles For Non-Interval Metered Loads With Distributed Renewable Generation

Load Profiles for non-interval metered Loads that utilize distributed renewable generation (e.g., PhotoVoltaic or wind) will be created using a hybrid approach. At least a portion of the Load Profile will be based on adjusted static models, while engineering estimates and/or generation models may be integrated as well or otherwise utilized.

18.2.9 Adjustments and Changes to Load Profile Development

ERCOT and the appropriate ERCOT TAC subcommittee will conduct an ongoing evaluation of the current Load Profiling Methodology. Together they will determine whether appropriate changes to the methodology should be made or whether another approach or combination of approaches is warranted. Any Market Participant may request a review of the Load Profiling Methodology. ~~A change from one~~ Adoption of a new Load Profiling Methodology ~~to another~~ must be approved by TAC, as provided in Section 18.2, Methodology.

Any Market Participant may petition ERCOT for adjustments to the existing Load Profiles and for development of new Load Profiles. The Market Participant making the request shall submit their proposal in writing to ERCOT. ERCOT will post to the Market Information System (MIS) the request and respond to such requests within sixty (60) days. ERCOT shall coordinate with the appropriate ERCOT TAC subcommittee for each change request. ERCOT shall strive to make the necessary changes within a reasonable period of time.

ERCOT, in coordination with the appropriate ERCOT TAC subcommittee, may make changes to existing Load Profiles and establish additional Load Profiles. All changes to Load Profiles shall adhere to these Protocols. When additional Load Profiles are established, ERCOT shall evaluate the impact on existing Load Profiles and associated load research samples.

A Market Participant may submit a request to ERCOT for conditional approval of a new Load Profile segment following the approval process as specified in the Load Profiling Guides, Section 12, Request for Profile Segment Changes, Additions, or Removals. In conjunction with this request, ERCOT staff shall specify the requirements for additional Load research sampling and shall define specific and objective criteria to be met by the analysis of this Load research data to meet the requirements for final approval. Provided the request for conditional approval has received the appropriate ERCOT committee approval and ERCOT staff determines the specified criteria are met, the request shall be granted final approval. If ERCOT staff determines the specified criteria are not met, the request shall be denied.

Section 9.9, Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment, describes the process for compensating the originator of a profile segment change request by REPs wishing to subscribe to the profile segment.

ERCOT shall give at least one hundred fifty (150) days notice to all Market Participants prior to market implementation of any change in Load Profile Methodology, existing Load Profiles, or when any additional Load Profiles are developed. This notice shall include a Load Profile change implementation timeline, which specifies dates on which key events during the Load Profile change process will take place. Upon any change in Load Profile Types, TDSPs shall send any revised ESI Load Profile assignments required by the change to the registration system within the implementation timeline. After the new Load Profile(s) becomes available, changes to Load Profile Types will be effective on the next meter read date for each ESI ID.

If one or more Load Profiles require changes to reduce excessive UFE, as determined by the appropriate ERCOT TAC subcommittee, TAC may provide a shorter notice period and implementation date, than otherwise provided herein, for such required changes to Load Profiles. If the Load Profile Methodology requires changes to reduce excessive UFE, as determined by the appropriate ERCOT TAC subcommittee, TAC may provide an expedited notice period and implementation date. TAC may require the standard Load Profile revision process follow such expedited revisions for long-term resolution.

Protocol Revision Request

PRR Number	757	PRR Title	Emergency Interruptible Load Service Formula Correction
Date Posted		March 7, 2008	

Protocol Section(s) Requiring Revision (Include Section No. and Title)	6.8.6, Capacity Payments for Emergency Interruptible Load Service (EILS) 6.9.4.4, Settlement Obligation for Emergency Interruptible Load Service
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal.
Revision Description	This Protocol Revision Request (PRR) proposes the following changes: • Revise the equation in Section 6.8.6(1) to eliminate subscript references to the term "b" (business hours) and replace it with reference term "tp" (time period) and delete a duplicate term in the variable definitions. • Revise the equation in subsection 6.9.4.4(3) to delete the undefined term "EILS Business Hours;" provide a definition for the subscript term "*i*"; and revise subscript term "*n*" from upper case to lower case to match its use in the equation.
Reason for Revision	The Protocols need to be internally consistent and consistent with PUC Substantive Rules. References to business hours and non-business hours were rendered obsolete by amendments to PUC SUBST. R. 25.507. Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS) and conforming PRR746, Revisions to EILS Provisions to Conform to Amended P.U.C. SUBST. R. 25.507. This PRR conforms the relevant subsections of the Protocols to other amendments made by PRR746, which was approved by the ERCOT Board on December 11, 2007.
Overall Market Benefit	Avoid potential confusion in the Protocols.
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications (Yes or No, and summary of impact)	None.

Protocol Revision Request

Relevance to Nodal Market (Yes or No, and summary of impact)	NPRR107, Emergency Interruptible Load Service (EILS), already includes these changes..
Nodal Protocol Section(s) Requiring Revision (Include Section No. and Title, and submit NPRR if applicable)	None. See prior comment.

Quantitative Impacts and Benefits

Assumptions	1	*This PRR corrects a omission from PRR 746 and should not have any market or system impacts.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1	*None*	*None*
	2	*None*	*None*
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Avoids Protocol confusion.*	*None*
	2		
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

Sponsor	
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Market Segment	n/a

Protocol Revision Request

Market Rules Staff Contact	
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Proposed Protocol Language Revision

6.8.6 Capacity Payments for Emergency Interruptible Load Service (EILS)

(1) EILS capacity payments will be paid, for each EILS Contract Period, to QSEs representing EILS Resources in the following manner:

$$\mathbf{EIL_{qce\underline{(tp)}\cancel{b}} = -1 * BIDPrice_{qce(tp)} * BIDValue_{qce(tp)} * AvailFactor_{qce(tp)} * EILFactor_{qce(tp)} * TPh}$$

$$QSE\_EIL_{qc(tp)} = \sum EIL_{qce(tp)}$$

$$Total\_BIDValue_{qc(tp)} = \sum BIDValue_{qce(tp)}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
tp	Hours in an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period
TPh	Number of hours in an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period, as calculated (and revised if necessary) in Section 6.10.13.3, Performance Criteria for EILS Resources
$BIDPrice_{qce(tp)}$	EILS Bid Price ($/MW) for each EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$BIDValue_{qce(tp)}$	Capacity (MW) for an EILS Resource contracted for EILS specific to an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$Total\_BIDValue_{qc(tp)}$	Total Capacity (MW) for an EILS Resource contracted for EILS specific to an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

~~$EILFactor_{qce(tp)}$~~	~~EILS event performance factor for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, as described in Section 6.10.13.3, Performance Criteria for EILS Resources~~
$EILFactor_{qce(tp)}$	EILS event performance factor for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, as described in Section 6.10.13.3, Performance Criteria for EILS Resources
$EIL_{qce(tp)}$	EILS total payment for an EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$QSE\_EIL_{qc(tp)}$	EILS total payment to QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

(2) ERCOT shall assess the settlement payment for EILS for each EILS Contract Period on the Initial Settlement Statement for an Operating Day no later than seventy (70) calendar days after the last Operating Day of the EILS Contract Period. For dispute purposes, ERCOT and QSEs shall use the Operating Day of the Settlement Statement on which the EILS payment appears. The timeliness of a dispute concerning EILS pursuant to Section 9.5.2, Notice, shall be determined by the Operating Day of the Settlement Statement on which the EILS payment appears.

[…]

6.9.4.4 Settlement Obligation for Emergency Interruptible Load Service

(1) EILS costs for an EILS Contract Period will be allocated based on the Load Ratio Share (LRS) of each QSE during each EILS Time Period in the EILS Contract Period. A QSE’s Load Ratio Share for an EILS Time Period in an EILS Contract Period will be the QSE’s total Load for the EILS Time Period in the EILS Contract Period divided by the total ERCOT Load in the EILS Time Period in the EILS Contract Period.

(2) If a QSE opts for EILS Self-Provision, the QSE’s Load Ratio Share for an EILS Time Period in an EILS Contract Period will be the QSE’s total Load for the EILS Time Period in the EILS Contract Period, divided by the total ERCOT Load in the EILS Time Period in the EILS Contract Period. The QSE’s Load Ratio Share for an EILS Time Period in an EILS Contract Period is then compared to the amount of EILS Self-Provision by the QSE for an EILS Time Period in an EILS Contract Period.

(a) If the EILS Self-Provision amount is equal to the QSE’s Load Ratio Share for an EILS Time Period in an EILS Contract Period, the QSE’s obligation is zero (0).

(b) If the EILS Self-Provision amount is greater than the QSE's Load Ratio Share for an EILS Time Period in an EILS Contract Period, the QSE's obligation is zero (0).

(c) If the EILS Self-Provision amount is less than the QSE's Load Ratio Share for an EILS Time Period in an EILS Contract Period, the QSE's obligation is the difference between the EILS Self-Provision amount and the QSE's Load Ratio Share.

(3) ERCOT shall calculate each QSE's obligation as follows:

$$\mathbf{LAEIL_{q(tp)} = EILP_{qc(tp)} * EILO_{qc(tp)}}$$

Where:

$$\mathbf{EILO_{qc(tp)} = Max[0,(LRS_{qc(tp)} * \ (Total\_BIDValue_{qc(tp)} + \sum(SP_{qc(tp)})) - SP_{qc(tp)}\underline{)}]}$$

$$\mathbf{EILP_{qc(tp)} = \sum(QSE\_EIL_{qc(tp)})\ / \sum EILO_{qc(tp)}}$$

$$\mathbf{SP_{qc(tp)} = \sum_{i=1}^{n} [(SPC_{qc(tp)}) * AvailFactor_{qce(tp)} * EILFactor_{qce(tp)}]}$$

Where:

q	QSE
c	Contract Period
tp	Hours in an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
n~~N~~	The number of EILS Resources the QSE is offering into the market
i	An index number used to identify a QSE's EILS Resource for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILO_{qc(tp)}$	EILS Net Obligation (MW) per QSE per hour for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$EILP_{qc(tp)}$	~~EILS Business Hours~~ Price for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period.
$SP_{qc(tp)}$	EILS self-provided by the QSE through EILS Self-Provision for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$Total\_BIDValue_{qc(tp)}$	Total Capacity (MW) for an EILS Resource contracted for EILS for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

$SPC_{qc(tp)}$	Self providing QSE's committed MW per hour for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Time Period, as defined in the ERCOT Request for Proposal for a specific Contract Period, as calculated (and revised if necessary) in Section 6.10.13.3, Performance Criteria for EILS Resources
$EILFactor_{qce(tp)}$	EILS event performance factor for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period, as described in Section 6.10.13.3, Performance Criteria for EILS Resources
$QSE\_EIL_{qc(tp)}$	EILS total payments to QSEs for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$LRS_{q(tp)}$	EILS Load Ratio Share for the QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period
$LAEIL_{q(tp)}$	EILS charge for the QSE for an EILS Time Period as defined in the ERCOT Request for Proposal for a specific EILS Contract Period

(4) ERCOT shall assess the settlement obligation as determined above for each EILS Time Period in an EILS Contract Period on the Initial Settlement Statement for an Operating Day no later than seventy (70) calendar days after the last Operating Day of the EILS Contract Period. For dispute purposes, ERCOT and QSEs shall use the Operating Day of the Settlement Statement on which the EILS payment appears. The timeliness of a dispute concerning EILS pursuant to Section 9.5.2, Notice, shall be determined by the Operating Day of the Settlement Statement on which the EILS obligation appears.

Protocol Revision Request

PRR Number	760	PRR Title	Emergency Interruptible Load Service (EILS) Availability Factor Clarification
Date Posted		March 20, 2008	

Protocol Section(s) Requiring Revision (Include Section No. and Title)	6.10.13.3 Performance Criteria for EILS Resources
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal
Revision Description	This Protocol Revision Request (PRR) clarifies a settlement and compliance provision relating to availability requirements for Emergency Interruptible Load Service (EILS) Resources assigned to the alternate baseline. The proposed changes are: • Revise language in subsection 6.10.13.3(b) to clarify that the minimum 95% availability factor requirement applies to all EILS Resources (assigned to either the default or alternate baselines), and that an availability factor of 95% or greater will not result in a reduction of an EILS Resource's capacity payment. As currently written, the language could be interpreted as treating EILS Resources inequitably depending on their baseline assignment; specifically, EILS Resources assigned to the alternate baseline could be subject to a capacity payment reduction for an availability factor of less than 100% but greater than 95%. (Default baseline EILS Resources are explicitly not subject to such a reduction.) This change is accomplished by moving language from existing 6.10.13.3(3)(b)(iii) up to the main section of subparagraph (3), thus clarifying that the 95% provision applies to EILS Resources assigned to either baseline. • This change also clarifies that any EILS Resource that fails to achieve 95% availability is deemed to have failed to meet its availability requirement, and is thus subject to a compliance violation in addition to a payment adjustment. • Revise certain other language in this subsection to make clarifying, non-substantive changes.
Reason for Revision	EILS settlement and compliance requirements must be consistent for all EILS Resources regardless of baseline assignment. This PRR provides clarification to avoid any potential confusion on the part of EILS participants. Protocol language relating to EILS, as originally approved in PRR705, Emergency Interruptible Load Service (EILS) - Interim Option, could be construed to imply that the availability requirements for EILS Resources assigned to the alternate baseline were different than for those assigned to the default baseline.

	The Technical Requirements and Scope of Work document published in conjunction with each EILS Contract Period has presented these elements of EILS as intended (with all EILS Resources treated equitably), and Market Participants and EILS Resources, including those committed in the current EILS Contract Period, are conducting their EILS operations in the belief that the baseline assignments are equitable. This PRR will ensure that such consistency is embedded unambiguously in the ERCOT Protocols.
Overall Market Benefit	Clarity in Protocol language for Qualified Scheduling Entities (QSEs) and EILS Resources.
Overall Market Impact	Unknown.
Consumer Impact	Unknown.
Credit Implications (Yes or No, and summary of impact)	None.
Relevance to Nodal Market (Yes or No, and summary of impact)	A similar Nodal Protocol Revision Request (NPRR) or ERCOT Staff Comments to NPRR 107 (Emergency Interruptible Load Service) will be filed.
Nodal Protocol Section(s) Requiring Revision (Include Section No. and Title, and submit NPRR if applicable)	8.1.3.1 Performance Criteria for EILS Resources

Quantitative Impacts and Benefits

Assumptions	1	*This PRR would affect only EILS Resources assigned to the Alternate Baseline who are calculated to have an availability factor of between 95% and 100%. This is likely to actually constitute only a small fraction of the overall committed EILS Resources.*	
	2	.	
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**

Protocol Revision Request

	1	*Potential increased EILS charge to QSEs representing Load.*	*For the current EILS Contract Period, if all committed EILS Resources were assigned to the Alternate Baseline, and all achieved an availability factor of exactly 95% resulting in reductions to their capacity payments of the maximum of 5%, the market impact would be as much as $267,000 (5% of the total projected EILS commitment of $5.34 million). QSEs representing Load are unlikely to consider this an unanticipated cost, however, as EILS has consistently been described as offering full (100%) payment to QSEs (and thus full uplift to QSEs representing Load) for any EILS Resource meeting or exceeding the 95% threshold.*
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1		
	2		
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Proposed Protocol Language Revision

6.10.13.3 Performance Criteria for EILS Resources

(1) EILS Default Baseline:

(a) As part of each EILS procurement process, ERCOT shall establish a unique baseline for each EILS Resource in an EILS bid, including each ESI ID if participating in an EILS aggregation. This baseline will be considered the default baseline for EILS Resources.

(b) The baseline has two (2) purposes:

(i) To verify or establish an EILS Resource's maximum bid capacity; and

(ii) To verify the EILS Resource's performance, as compared to its contracted capacity, during an EILS deployment event.

(c) In order to determine a baseline for each EILS Resource, ERCOT will create a default baseline formula to predict the interval Load based on variables which will include an ESI ID's historic Load data, weather, time of day and other relevant calendar information. ERCOT may use other data variables in the default baseline formula at ERCOT's sole discretion, if ERCOT determines the additional data will enhance the accuracy of the default baseline. Development of the default baseline for each EILS Resource will be consistent with practices used in developing ERCOT Load Profile models. The methodology for developing the default baseline formula will be documented and published on ERCOT's MIS.

(d) ERCOT will establish the default baseline for an aggregated EILS Resource by adding the default baselines of the individual ESI IDs in the aggregation. The performance of an aggregated EIL Resource shall be verified by ERCOT at the EILS Resource level.

(e) ERCOT will develop a default baseline for each EILS Resource by analyzing fifteen (15) minute interval usage data for the most recent twelve (12) month period available. ERCOT may use additional historic data at its sole discretion. Upon request, ERCOT shall provide the historical data used to develop the default baseline for an EILS Resource to the Entity responsible for that EILS Resource.

(f) Based on ERCOT's analysis of data in establishing a default baseline for an EILS Resource, ERCOT may reduce the amount of capacity an EILS Resource may be awarded in a given EILS Contract Period.

(g) Upon request, ERCOT shall provide default baseline analysis results for an EILS Resource to the Entity representing that EILS Resource.

(2) Alternate EILS Baseline Using Twelve (12) Month Average:

(a) ERCOT shall apply its default baseline formula to all EILS Resources unless, in ERCOT's reasonable discretion, a sufficiently accurate baseline cannot be established due to the characteristics of the Load or Loads within an EILS Resource. In such cases, ERCOT may apply a single alternate baseline formula to all ESI IDs within such EILS Resource.

(b) Under the alternate baseline formula, ERCOT shall calculate an EILS Resource's average (mean) IDR-metered Load (MWh) over the most recent available twelve (12) month period. ERCOT will establish an adjusted MW capacity for each EILS Resource for the applicable EILS Time Period, based upon the difference between this average Load calculation (MWh) and the EILS Resource's declared minimum base Load (MWh). In selecting an EILS Resource with an alternate baseline, ERCOT may award the lesser of the MW bid or the adjusted MW capacity calculated by ERCOT. When deployed by ERCOT, the EILS Resource assigned to an alternate baseline shall curtail down to its minimum base Load or below, regardless of how much actual Load the EILS Resource has online at the time of deployment.

(3) End of Contract Period Availability Review and Capacity Payment Adjustments:

(a) Within forty-five (45) days after the end of an EILS Contract Period, ERCOT will complete an availability review for each EILS Resource that was contracted for that EILS Contract Period. In its availability review, ERCOT will determine an "availability factor" for each EILS Resource in that EILS Contract Period.

(b) ~~For an EILS Resource assigned to the default baseline,~~ ERCOT will determine the availability factor for an EILS Resource ~~by calculating the number of hours an EILS Resource was available as contracted during the EILS Contract Period divided by the total hours in the EILS Contract Period~~. An availability factor of 95% or greater for an EILS Resource shall result in no reduction in capacity payment for the EILS Resource (*i.e.*, ERCOT shall set the availability factor at 100%), and the EILS Resource will be deemed to have complied with its availability requirements. If an EILS Resource's availability factor for an EILS Contract Period falls below 95%, ERCOT shall set the EILS Resource's availability factor at its actual availability factor, and the EILS Resource will be deemed to have failed to meet its availability requirements which may result in a capacity payment adjustment. The calculations to determine the availability factor to be used for settlement purposes are as follows:

$$\textbf{AvailFactor}_{qce(tp)r} = 1 \textbf{ if AvailFactor}_{qce(tp)} >= .95\textbf{, else AvailFactor}_{qce(tp)r} = \textbf{AvailFactor}_{qce(tp)}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

$AvailFactor_{qce(tp)}$	EILS availability factor for the EILS Time Period, as defined in the ERCOT Request for Proposal for the EILS Contract Period, as determined in subsection (3)(b) above
$AvailFactor_{qce(tp)r}$	Revised EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(c) For an EILS Resource assigned to the default baseline, ERCOT will calculate its availability factor as follows:

(i) ERCOT will consider the EILS Resource to have been available for any hour in which the EILS Resource's IDR-metered Load was greater than 95% of its contracted EILS MW capacity (bid capacity plus declared minimum base Load); otherwise, the EILS Resource will be considered unavailable for that hour. The availability factor will be the ratio of the number of hours the EILS Resource was available during the EILS Contract Period divided by the total hours in the EILS Contract Period.

(ii) Notwithstanding the foregoing, an EILS Resource will be considered as if it were "available" for purposes of determining the availability factor in:

(A) Any hours for which the EILS Resource's QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Resource's unavailability at least five (5) Business Days in advance, up to a maximum of two (2) percent of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an EECP was in effect, starting with initiation of Step 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

~~(iii) An availability factor of 95% or greater for an EILS Resource shall result in no reduction in capacity payment for the EILS Resource (*i.e.*, ERCOT shall set the availability factor at one (1)). If an EILS Resource's availability factor for an EILS Contract Period falls below 95%, ERCOT shall set the EIL Resource's availability factor at its actual availability factor as calculated above. The calculations to determine the availability factor to used for settlement purposes are as follows:~~

$$\cancel{\mathbf{AvailFactor_{qce(tp)r} = 1 \text{ if } AvailFactor_{qce(tp)} >= .95, \text{ else } AvailFactor_{qce(tp)r} = AvailFactor_{qce(tp)}}}$$

~~Where:~~

~~q~~	~~QSE~~
~~c~~	~~Contract Period~~

~~e~~	~~Individual EILS Resource~~
~~tp~~	~~EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period~~
~~$AvailFactor_{qce(tp)}$~~	~~EILS availability factor for the EILS Time Period, as defined in the ERCOT Request for Proposal for the EILS Contract Period, as determined in subsection (3)(b) above~~
~~$AvailFactor_{qce(tp)r}$~~	~~Revised EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period~~

(~~c~~d) For an EILS Resource assigned to the alternate baseline, ERCOT will ~~determine~~ calculate its availability factor as follows:

(i) ERCOT shall divide the EILS Resource's actual average Load per hour (excluding its declared minimum base Load, if any) for the contracted hours in the EILS Time Period and EILS Contract Period by the ~~potential energy production possible in one hour based upon the~~ EILS Resource's contracted ~~adjusted~~ MW bid ~~(as determined via the alternate baseline calculation described above);~~, provided that the availability factor shall not be greater than one (1).

(ii) In determining the EILS Resource's average actual Load,

(A) ERCOT shall exclude from the average any hours for which the EILS Resource's QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Resource's unavailability at least five (5) Business Days in advance, up to a maximum of two percent of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an EECP was in effect, starting with initiation of Step 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

(iii) The calculations for the alternate baseline availability factor are as follows:

$$\mathbf{AvailFactor_{qce(tp)} = MIN (1, (AV_{(tp)}/(h*BIDValue_{qce(tp)})))}$$

Where:

q	QSE
c	EILS Contract Period
e	individual EILS Resource
tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
h	hour

AV_{tp}	Average Load per hour for contracted EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period (MWh) excluding declared minimum base Load
$BIDValue_{qce(tp)}$	Capacity (MW) for an EILS Resource contracted for an EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for an EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(~~d~~e) In the event an EILS Resource that is part of a QSE's EILS Self-Provision obligation fails to meet its availability requirement for a Contract Period, ERCOT shall adjust the EILS Resource's QSE's Settlement obligation to reflect the actual availability factor by modifying the term "SP" in Section 6.9.4.4, Settlement Obligation for Emergency Interruptible Load Service, item (3). An EILS Resource that is part of a QSE's EILS Self-Provision that achieves an availability factor of 0.95 or greater shall be considered to have met its availability requirement.

(4) EIL Resources' Compliance During an EIL Deployment Event and Capacity Payment Adjustments:

(a) Upon ERCOT's issuance of a Verbal Dispatch Instruction (VDI) during EECP Step 3 requesting EIL deployment, EILS Resources assigned to the default baseline must curtail at least 95% of available contracted capacity within ten (10) minutes of receiving the VDI and must stay at or below that level until released by ERCOT. EILS Resources assigned to the alternate baseline must curtail to their declared minimum base Load or below, and must stay at or below that level until released by ERCOT.

(b) ERCOT shall measure each EILS Resource's compliance with this requirement through analysis of fifteen (15) minute IDR data from each ESI ID. ERCOT will determine an event performance factor for each EILS Resource based upon this analysis.

(c) For an EILS Resource assigned to a default baseline, the event performance factor (EILFactor) is computed as the arithmetic average of the EILS Interval Performance Factors (EIPF) for the entire curtailment period.

An EIPF is computed for the EILS Resource for each of the fifteen (15) minute intervals during which an EIL curtailment is required. For an interval, $EIPF_i$ is computed as follows:

$$\mathbf{EIPF_i = Max(Min(((Base\_MWh_i - Actual\_MWh_i) / (IntFrac_i \times BIDValue)),1),0)}$$

Where:

i	interval
$IntFrac_i$	interval fraction for that EILS Resource for that interval
$Base\_MWh_i$	aggregated sum of the baseline MWh values estimated by ERCOT for all ESI IDs in the EILS Resource for that interval
$Actual\_ MWh_i$	aggregated sum of the actual MWh values for all ESI IDs in the EILS Resource for that interval
BIDValue	aggregated sum of the capacity bid by the EILS Resource in MWh

and where $IntFrac_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect and is computed as follows:

$$\mathbf{IntFrac_i = (CEndT_i - CBegT_i) / 15}$$

Where:

i	interval
$CBegT_i$	if the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero (0)
$CEndT_i$	if the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is fifteen (15)

(d) For an EILS Resource assigned to an alternate baseline, the EILFactor is computed as the arithmetic average of the EILS Interval Performance Factors (EIPF) for the entire curtailment period.

An EIPF is computed for the EILS Resource for each of the fifteen (15) minute intervals during which an EIL curtailment is required. For an interval, $EIPF_i$ is computed as follows:

For the first interval in the curtailment period,

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min((((1-IntFrac_i)\times Actual\_MWh_{i-1} + (IntFrac_i \times Min\_MWh)) / Actual\_MWh_i),1)}$$

For the last interval in the curtailment period,

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min((((1\text{-}IntFrac_i) \times Actual\_MWh_{i+1} + (IntFrac_i \times Min\_MWh)) / Actual\_MWh_i),1)}$$

And for all other intervals in the curtailment period

If $Actual\_MWh_i = 0$ then $EIPF_i = 1$,

Otherwise

$$\mathbf{EIPF_i = Min(Min\_MWh / Actual\_MWh_i),1)}$$

Where:

i	interval
$IntFrac_i$	interval fraction for that EILS Resource for that interval
Min_MWh	aggregated sum of the minimum base Load in MWh values bid for all ESI IDs in the EILS Resource for that interval
$Actual\_ MWh_i$	aggregated sum of the actual MWh values for all ESI IDs in the EILS Resource for that interval

and where $IntFrac_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect and is computed as follows:

$$\mathbf{IntFrac_i = (CEndT_i - CBegT_i) / 15}$$

Where:

i	interval
$CBegT_i$	if the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero (0)
$CEndT_i$	if the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is fifteen (15)

(e) In the event that an EILS Resource does not meet its performance obligations according to the appropriate methodology described above, ERCOT may, in its sole discretion, adjust the EILS Resource's event performance factor to reflect the severity of the failure. The event performance factor for an EILS Resource may be any number from zero (0) to one (1), inclusive. An EILS Resource that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance obligations for that event.

(f) In any EILS Contract Period in which ERCOT has issued one (1) or more EIL deployments, if an EILS Resource meets its obligation established in subsection (4)(a), above, for all intervals of all EIL deployments, its availability factor shall be the greater of the availability factor calculated by ERCOT pursuant to subsection (3) above or 50%, whichever is greater. ERCOT shall apply the calculations below for a EILS Contract Term in which there was at least one EECP event in which ERCOT deployed EILS Resources:

$$\mathbf{AvailFactor_{qce(tp)r} = MAX(.5, AvailFactor_{qce(tp)})}$$

Where:

q	QSE
c	Contract Period
e	Individual EILS Resource
r	Revised pursuant to Subparagraph (e) or (f) above
tp	EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period
$AvailFactor_{qce(tp)}$	EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period, as determined in subsection (3)(e) above
$AvailFactor_{qce(tp)r}$	Revised EILS availability factor for the EILS Time Period as defined in the ERCOT Request for Proposal for the EILS Contract Period

(g) In the event an EILS Resource that is part of a QSE's EILS Self-Provision obligation does not meet its performance requirement, ERCOT shall adjust the EILS Resource's Settlement obligation to reflect the actual performance factor by modifiying the term "SP" in Section 6.9.4.4, Settlement Obligation for Emergency Interruptible Load Service, item (3). An EILS Resource that is part of a QSE's EILS Self-Provision that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance requirement for that EILS event.

Nodal Protocol Revision Request

NPRR Number	**105**	**NPRR Title**	**Section 23, Synchronization of Zonal Protocols**
Date Posted	February 26, 2008		

Protocol Section Requiring Revision	Section 23, Texas Test Plan Team – Retail Market Testing
Requested Resolution	Normal
Revision Description	This Nodal Protocol Revision Request (NPRR) synchronizes zonal Protocol Section 23 with the current Nodal Protocols.
Reason for Revision	Synchronization of remaining zonal Protocol sections with the Nodal Protocols.
Overall Market Benefit	Completion of Nodal Protocols.
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications	TBD
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	

Quantitative Impacts and Benefits

Assumptions	1	*Synchronization changes are administrative in nature and should have no impact or minimal impact on the market.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**

Nodal Protocol Revision Request

	1		
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Completion of Nodal Protocols.*	
	2	*Synchronization of remaining zonal Protocol sections with the Nodal Protocols.*	
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Comments

A new “Definitions Section” has been added to the beginning of Section 23 for defined terms used only in this Section. Either definitions will need to be added for terms that are not defined but are capitalized throughout Section 23 or such terms should be made lower case if stakeholders choose not to define them.

Nodal Protocol Revision Request

Proposed Protocol Language Revision

ERCOT Nodal Protocols
Section 23: Texas Test Plan Team – Retail Market Testing

~~September 1, 2005~~

(Effective Upon Texas Nodal Market Implementation)

~~23~~23~~12~~ TEXAS TEST PLAN TEAM – RETAIL MARKET TESTING

This Section contains an overview of the purpose and scope of the Texas Test Plan Team (TTPT). It also refers to the standards that are defined in the Texas Market Test Plan (TMTP) posted on the ERCOT Market Information System (MIS) Public Area. This Section applies to ERCOT, Competitive Retailers (CR), and ~~and~~ Transmission Service Providers (TSP) and/or Distribution Service Providers (DSP~~s~~) serving areas where Customer Choice is in effect. ~~This information is posted on the ERCOT website.~~

SECTION 23 DEFINITIONS

The following definitions are supplied for terms used only in this Section.

ERCOT Flight Administrator ***(definition needed)***

Independent Third Party Testing Administrator (ITPTA) ***(definition needed)***

23.1 Overview

(1) The Texas Test Plan Team (TTPT) is an ERCOT standing working group that reports to the Retail Market Subcommittee (RMS). The TTPT is comprised of volunteers from Market Participant ~~(MP)~~ companies. These volunteers work in a cooperative manner to establish processes and procedures for testing the commercial operations to verify retail systems are in compliance with the ERCOT Protocols and Public Utility Commission of Texas (PUCT) ~~rulemakings~~Substantive Rules.

(2) The TTPT processes and procedures for testing represent the consensus view of Market Participants directly involved in the testing process.

(3) The TTPT evaluates market processes defined by the ERCOT Protocols, other ~~Retail Market Subcommittee~~RMS working groups, and PUCT ~~rulemakings~~ Substantive Rules to establish testing requirements and materials necessary to validate those processes among Market Participants.

(4) ERCOT may enlist the services of an Independent Third Party Testing Administrator (ITPTA) in this testing process.

(5) The TTPT works with the ERCOT Flight Administrator to ensure that testing processes and procedures are defined for the ERCOT ~~M~~market and that the content of those materials are thoroughly and equitably administered with all participants.

23.2 Testing Participants

The following parties conduct market compliance testing and abide by the testing process defined by the Texas Test Plan Team (TTPT)~~ (Texas Test Plan Team)~~:

(a~~1~~) ERCOT;

(b~~2~~) Transmission Service Provider (TSP);

(c) Distribution Service Provider (DSP)~~TDSP~~; and

(d~~3~~) Competitive Retailer (CR).

23.3 Documentation and Testing Materials

The Texas Test Plan Team (TTPT) ~~(Texas Test Plan Team)~~ develops and maintains a test plan and related testing standards. The processes and procedures for testing are defined in the Texas Market Test Plan (TMTP) posted on the ERCOT Market Information System (MIS) Public Area~~and on the retail testing website, which is administered by ERCOT~~.

23.4 Market Changes

The Texas Test Plan Team (TTPT)~~ (Texas Test Plan Team)~~ stays abreast of changes within the ERCOT market (e.g. Texas Standard Electronic Transaction (Texas~~X~~ SET) Implementation Guides~~guidelines~~, Texas Data Transport Working Group (TDTWG) communication p~~P~~rotocols, ERCOT Protocols, and Public Utility Commission of Texas (PUCT) ~~rulemakings~~Substantive Rules) and develops testing processes to validate changes. When such changes occur, the ~~Texas Test Plan Team (~~TTPT~~)~~ modifies the testing standards defined in the Texas Market Test Plan (TMTP) as needed to provide for adequate testing of all affected market systems. Testing of these changes is scheduled to allow ERCOT and all Market Participants~~ (MPs)~~ adequate time to modify their systems and participate in the testing process.

23.5 Testing Success

Testing success is defined according to the information in the Texas Market Test Plan (TMTP) and the test scripts. The ERCOT Flight Administrator is the final authority on all levels of business process certification among trading partners, including the verification that a party has successfully passed testing and is eligible to go into production.

Nodal Protocol Revision Request

NPRR Number	106	NPRR Title	Section 24, Synchronization of Zonal Protocols
Date Posted		February 26, 2008	

Protocol Section Requiring Revision	Section 24, Retail Point-to-Point Communications
Requested Resolution	Normal
Revision Description	This Nodal Protocol Revision Request (NPRR) synchronizes zonal Protocol Section 24 with the current Nodal Protocols.
Reason for Revision	Synchronization of remaining zonal Protocol sections with the Nodal Protocols.
Overall Market Benefit	Completion of Nodal Protocols.
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications	TBD.
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	

Quantitative Impacts and Benefits

Assumptions	1	*Synchronization changes are administrative in nature and should have no impact or minimal impact on the market.*	
	2		
	3		
	4		
Market Cost		Impact Area	Monetary Impact

Nodal Protocol Revision Request

	1		
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Completion of Nodal Protocols.*	
	2	*Synchronization of remaining zonal Protocol sections with the Nodal Protocols.*	
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Comments

A new "Definitions Section" has been added to the beginning of Section 24 for defined terms used only in this Section. Either definitions will need to be added for terms that are not defined but are capitalized throughout Section 24 or such terms should be made lower case if stakeholders choose not to define them.

Nodal Protocol Revision Request

Proposed Protocol Language Revision

ERCOT Nodal Protocols
Section 24: Retail Point to Point Communications

~~June 25, 2007~~

(Upon Texas Nodal Market Implementation)

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24 RETAIL POINT TO POINT COMMUNICATIONS

Point to point communications include transactions flowing directly between Competitive Retailers (CRs), -and Transmission ~~and/or~~ Service Providers (TSPs) and/or Distribution Service Providers (DSPs) ~~(TDSPs)~~ and do not flow through ERCOT. These point to point transactions may be Customer requested service orders and CR/TSP/DSP invoicing and remittance.

SECTION 24 DEFINITIONS

The following definitions are supplied for terms used only in this Section.

Applicable Legal Authority (ALA)

A Texas or federal law, rule, regulation, or applicable ruling of the Commission or any other regulatory authority having jurisdiction, an order of a court of competent jurisdiction, or a rule, regulation, applicable ruling, procedure, Protocol, guide or guideline of the Independent Organization, or any Entity authorized by the Independent Organization to perform registration or settlement functions.

Late Payment *(definition needed)*

Service Address *(definition needed)*

24.1 Maintenance Service Order Request

To initiate an original service order, cancel, or change (update) request, the Competitive Retailer (CR) sends maintenance related information to the Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) ~~TDSP~~ using the 650_01, Service Order Request. The 650_01 sent by the CR shall include a level of information such that the TSP and/or DSP clearly understands the nature of the request and the work that it is being requested to perform. The T~~D~~SP and/or DSP will respond within one ~~(1)~~ Retail Business Day after completion, or attempted completion, of the requested action using the 650_02 to notify the CR that the service order is either completed, unable to be completed, or rejected, or that a permit is required before the order can be completed. There is a one-~~-~~to-~~-~~one relationship between the 650_01 and 650_02 service order request/response transactions.

24.1.1 Disconnect/Reconnect

Public Utility Commission of Texas (PUCT) ~~rules and regulations~~Substantive Rules and ~~decisions~~orders, along with TSP and/or DSP~~s~~ Tariffs, dictate the timeline for both disconnection for non-payment and reconnection after disconnection for non-payment. For more information please refer to the Retail Market Guide (RMG) Section 7.6, Disconnect and -Reconnect for Non-Payment Process.

24.1.2 Suspension of Delivery Service

The following transactions shall be used by a TSP and/or DSP seeking to suspend delivery service for an Electric Service Identifier (ESI ID).

24.1.2.1 Notification

(1) The 650_04, Suspension of Delivery Service Notification, transaction is electronically transmitted by the TSP and/or DSP to the CR to notify the CR of the ESI ID(s) and Service Address(es) affected by either a temporary or permanent suspension of service. The situations under which a 650_04 transaction may be created and transmitted to the CR include:

(a~~1~~) An outage has been scheduled by the TSP and/or DSP for the Customer's Service Address for a specific date and time. This type of suspension may be the result of scheduled tree trimming, electrical inspection, testing, maintenance, or changes/upgrades to network equipment.

(b~~2~~) An ~~O~~o~~o~~utage has occurred at the Customer's Service Address, but it was not planned or previously scheduled. Such a suspension is normally needed to remedy a dangerous electrical condition that exists at the Customer's address due to an event or activity such as a fire, meter tampering, or theft of service.

(c~~3~~) For circumstances when a CR, the Customer, or authorized legal authority (c~~C~~ounty, c~~C~~ity, f~~F~~ire, or p~~P~~olice personnel) requests disconnection and meter removal because a structure has been destroyed or demolished, or the TSP and/or DSP has found the meter removed by an unknown entity, or has removed the meter for unsafe conditions, the TSP and/or DSP will send a 650_04. In events where the CR receives a 650_04 indicating that service to the Premise has been permanently suspended by the TSP and/or DSP for one of the reasons indicated above, the CR will send an 814_24, Move-Out Request, to the TSP and/or DSP within ten ~~(10)~~ Retail Business Days.

(d~~4~~) Just like a suspension is scheduled or requested it can also be cancelled. If the suspension request is cancelled for any reason, the TSP and/or DSP will create a 650_04 ~~notification~~ Notification indicating that the suspension has been cancelled and send a 650_04 ~~notification~~ Notification to the CR for every ESI ID that would have been affected by the outage.

(2) To notify the CR of a suspension of delivery service, the TSP and/or DSP sends ~~notice~~ Notice to the CR using the 650_04. To reject the suspension of delivery service ~~notification~~Notification, a CR would send a response to the TSP and/or DSP using the 650_05, Suspension of Delivery Service Reject Response, within one ~~(1)~~ Retail Business Day of receipt of the 650_04.

24.1.2.2 Cancellation

To notify the CR of a cancellation of the ~~notification~~ Notification of suspension of delivery service, the TSP and/or DSP sends ~~notice~~ Notice to the CR using the 650_04 for each ESI ID that would otherwise have been affected by the outage. To reject the suspension of delivery service cancellation, a CR must send a response to the TSP and/or DSP using the 650_05 within one ~~(1)~~ Retail Business Day of receipt of the 650_04.

24.2 Transmission Service Provider and/or Distribution Service Provider to Competitive Retailer Invoice

(1) The 810_02, Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) to Competitive Retailer (CR) Invoice, may include monthly delivery charges, discretionary service charges, service order charges, interest credit, and/or Late Payment charges for the current billing period. Following a positive acknowledgement indicating the transaction passed ANSI X12 validation, the CR shall have five ~~(5)~~ Business Days to send a rejection response in accordance with the Texas Standard Electronic Transaction (Texas~~X~~ SET) Implementation Guides posted on the ERCOT Market Information System (MIS) Public Area and Public Utility Commission of Texas (PUCT) ~~rules~~Substantive Rules. If the CR has not received a response transaction to an enrollment or move-in, the CR shall not reject the invoice, but will utilize an approved market process (MarkeTrak or Dispute Process) to resolve the issue. Details of these processes ~~can~~may be found in the Retail Market Guide (RMG) Section 7, Market Processes.

(2) Only one 810_02 may be sent for a single service period, however, any additional 810_02 for the same Electric Service Identifier (ESI ID) may be sent for a Late Payment charge after the ~~thirty fifth (~~35th~~)~~ calendar day for an unpaid 810_02 or for interest credit.

(3) The 810_02 may be paired with an 867_03, Monthly Usage, to trigger the Customer billing process.

(4) The TSP and/or DSP may cancel and replace (rebill) the original 810_02. The values in the cancel transaction will be identical in amounts to what they were on the original i~~I~~nvoice. The replacement (rebilled) i~~I~~nvoice now becomes the monthly i~~I~~nvoice for that service period.

(5) If the 867_03 is cancelled after the TSP and/or DSP has sent the 810_02, the TSP and/or DSP will cancel the 810_02. If the 810_02 error is not related to consumption, the TSP and/or DSP may cancel the 810_02 and not the 867_03.

24.3 Monthly Remittance

Transmission Service Providers (TSP) and/or Distribution Service Providers (DSP)~~s~~ and Competitive Retailers (CR)~~s~~ shall use the following transactions to remit monthly payments.

24.3.1 CR to TSP and/or DSP Monthly Remittance Advice

(1) This transaction set, from the CR to the TSP and/or DSP, is used by the CR to notify the TSP and/or DSP of payment details related to a specific i~~I~~nvoice. A CR must pass an 820_02, CR Remittance Advice, for every ~~Invoice~~ invoice (original, cancel, replacement) received, validated, and accepted by the CR even when a cancel and restatement of usage subsequently cancels the original i~~I~~nvoice.

(2) Each Market Participant ~~(MP)~~ is responsible for ensuring that the data provided in the 820_02 is presented in a format that is consistent with market specifications prescribed in the Texas Standard Electronic Transaction (Texas~~X~~ SET) 820_02 Implementation Guide posted on the ERCOT Market Information System (MIS) Public Area.

24.3.1.1 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The CR must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to~~-~~one correlation must be maintained between payments and remittance advices. It is acceptable for one payment and one remittance advice to include many invoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the TSP and/or DSP. The trace/reference number must be unique for each associated payment and remittance advice.

24.3.1.2 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas retail market. If the adjustments are larger than the payments (creating a negative remittance advice), payments must be held until the CR can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a CR to hold an adjustment amount until the CR has accumulated sufficient ~~Invoices~~ invoices to result in a complete offset of the overpayment. Instead the CR may use the adjustment amount by taking a partial credit on another Invoice. If the CR has determined that the negative remittance cannot be offset within a reasonable amount of time, the CR will contact the TSP and/or DSP to resolve the situation.

24.3.1.3 Acceptable Payment Methods

Acceptable payment methods are CCD+, CTX and Fed wire.

24.3.1.4 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the TSP and/or DSP will warehouse the 820_02 until the payment instructions received by the CR's bank cause the money to be deposited in the TSP's and/or DSP's account. The payment instruction and remittance shall be transmitted within five ~~(5)~~ Business Days of each other. The remittance advice and payment instruction dollar amount must balance to the corresponding transaction. Payment will be considered received on the date company's bank receives the electronic funds transfer or wire transfer and the appropriate remittance advice is received by the company in accordance with the requirements specified by Applicable Legal Authorities.

24.4 MOU/EC TSP and/or DSP to CR Monthly Remittance Advice

(1) This transaction set, from a Municipally Owned Utility's (MOU) Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) or an Electric Cooperative's (Coop) TSP and/or DSP (MOU/EC TSP and/or DSP) to the Competitive Retailer (CR) is used by the MOU/EC T~~D~~SP and/or DSP to notify the CR of payment details related to a specific Invoice. A MOU/EC T~~D~~SP and/or DSP must pass an 820_03, Remittance Advice, for every CR account number even when a cancel and restatement of usage subsequently cancels the original i~~I~~nvoice.

(2) Each Market Participant (MP) is responsible for ensuring that the data provided in the 820_03 is presented in a format that is consistent with the market specifications in the Texas Standard Electronic Transaction (Texas~~X~~ SET) Implementation Guide.

24.4.1 Timing 820 Remittance to CR

When the payment is received from the retail Customer on behalf of the CR, MOU/EC T~~D~~SP and/or DSP shall send the payment instructions within five ~~(5)~~ Retail Business Days of the due date of the retail Customer's bill, or if the Customer has paid after the due date, five ~~(5)~~ Business Days after the MOU/EC T~~D~~SP and/or DSP has received payment. Payment instruction shall cause the money to be deposited in the CR's account. There should not be more than five ~~(5)~~ Business Days difference in the receipt of the payment instruction and the remittance advice.

24.4.2 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The MOU/EC T~~D~~SP and/or DSP must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to-~~-~~one correlation must be maintained between payments and remittance advice. It is acceptable for one payment and one remittance advice to include many i~~I~~nvoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the CR. The trace/reference number must be unique for each associated payment and remittance advice.

24.4.3 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas market. If the adjustments are larger than the payments (creating a negative remittance advice), payment must be held until the

MOU/EC T~~D~~SP and/or DSP can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a MOU/EC T~~D~~SP and/or DSP to hold an adjustment amount until the MOU/EC T~~D~~SP and/or DSP has accumulated sufficient Invoices to result in a complete offset of the overpayment. Instead the MOU/EC T~~D~~SP and/or DSP may use the adjustment amount by taking a partial credit on another Invoice. If the MOU/EC T~~D~~SP and/or DSP has determined that the negative remittance cannot be offset within a reasonable amount of time, the MOU/EC T~~D~~SP and/or DSP will contact the CR to resolve the situation.

24.4.4 Acceptable Payment Methods

Acceptable payment instruction methods are CCD+, CTX, check, and Fed wire.

24.4.5 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the CR may warehouse the 820_03 remittance until the payment instructions received by the MOU/EC TSP's and/or DSP's bank cause the money to be deposited in the CR's account.

24.5 Maintain Customer Information Request

This transaction set, from a Competitive Retailer (CR) to a Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP), is used for CRs who have chosen Options 2 and 3 concerning service orders and/or outages. A CR choosing Option 2 or 3 shall be required to provide the TSP and/or DSP with the information necessary to verify CR's retail Customer's identity (name, address, and home or contact telephone number) for a particular point of delivery served by the CR and to continually provide the TSP and/or DSP updates of such information.

24.5.1 Timing of 814_PC Maintain Customer Information Request from CR

This transaction shall be transmitted from the CR of Record to the TSP and/or DSP in one ~~(1)~~ Retail Business Day only after the CR has received an 867_04, Initial Meter Read Notification, from the TSP and/or DSP for that specific move-in Customer. Also, the CR shall not transmit this transaction and/or provide any updates to the TSP and/or DSP after receiving a final reading via an 867_03, Monthly Usage, for that specific move-out Customer. The TSP and/or DSP shall provide the 814_PD, Maintain Customer Information Response, transaction in one ~~(1)~~ Retail Business Day acknowledging receipt of the 814_PC, Maintain Customer Information Request, transaction~~,~~ which would indicate that the TSP and/or DSP accepts or rejects the transaction.

24.6 MOU/EC T~~D~~SP and/or DSP to CR Maintain Customer Information Request

This transaction set, from a Municipally Owned Utility (MOU)/Electric Cooperative (EC) ~~OU/EC~~ Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) to the Competitive Retailer (CR), is used by the MOU/EC TSP and/or DSP to provide the CR with

Customer information (name, address, membership id, and home or contact telephone number) for a particular point of delivery served by both the MOU/EC TSP and/or DSP and CR and to continually provide the CR updates of such information. MOU/EC TSPs and/or DSPs in a MOU/EC service territory are more likely to have current Customer information due to the fact that they maintain contact with the Customer and perform billing functions.

24.6.1 Timing of 814_PC Maintain Customer Information Request from MOU/EC T~~D~~SP and/or DSP

This transaction shall be transmitted from the MOU/EC TSP and/or DSP to the CR in one ~~(1)~~ Retail Business Day upon an update in Customer information. The CR shall provide the 814_PD transaction in one ~~(1)~~ Retail Business Day acknowledging receipt of the 814_PC transaction, which would indicate that the CR accepts or rejects the transaction.

Protocol Revision Request

NPRR Number	**108**	**NPRR Title**	**Fuel Oil Price (FOP) Clarification**
Date Posted		March 3, 2008	

Protocol Section Requiring Revision (Include Section No. and Title)	Section 2.1, Definitions
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal
Revision Description	This Nodal Protocol Revision Request (NPRR) clarifies that the five-cent adder is charged by the gallon and removes language referencing to the Fuel Oil Price (FOP) for days when the *Platts Oilgram Price Report* is not published
Reason for Revision	Corrects application of five-cent adder and method for FOP substitution on days when FOP is not provided in the *Platts Oilgram Price Report*.
Overall Market Benefit	Accurate definition for the meaning and use of the term.
Overall Market Impact	None
Consumer Impact	None
Credit Implications (Yes or No, and summary of impact)	None
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	On 2/21/08, TPTF unanimously voted to endorse submitting to PRS for consideration the Draft NPRR for FOP Clarification as submitted to TPTF on February 21, 2008.

Protocol Revision Request

Quantitative Impacts and Benefits

Assumptions	1	*Definitions should accurately reflect the meaning and use of a term.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1	*None*	*None*
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*None*	*None*
	2	*Reduced congestion cost*	
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Proposed Protocol Language Revision

Fuel Oil Price (FOP)

The sum of five cents per gallon plus the average of the *Platts Oilgram Price Report* for U.S. Gulf Coast, pipeline No. 2 oil, converted to dollars per million British thermal units ($/MMBtu). The conversion is 0.1385 MMBtu per gallon. The *Platts Oilgram Price Report* indicates which Operating Days the prices are effective. ~~For Saturdays, Sundays, holidays, and other days for which *Platts Oilgram Price Report* does not publish an effective price, the effective price shall be the effective price for the Operating Day following the holiday or day without a published price.~~ In the event, at the time of settlement or calculation of generic costs, that the effective price for a particular Operating Day is not available, the effective price for the most recent preceding Operating Day shall be used.

Nodal Protocol Revision Request

NPRR Number	109	**NPRR Title**	Section 18, Synchronization of Zonal Protocols
Date Posted	March 3, 2008		

Protocol Section Requiring Revision	Section 18, Load Profiling
Requested Resolution	Normal.
Revision Description	This Nodal Protocol Revision Request (NPRR) synchronizes zonal Protocol Section 18 with the current Nodal Protocols.
Reason for Revision	Synchronization of remaining zonal Protocol sections with the Nodal Protocols.
Overall Market Benefit	Completion of Nodal Protocols.
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications (Yes or No, and summary of impact)	None.
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	

Quantitative Impacts and Benefits			
Assumptions	1	*Synchronization changes are administrative in nature and should have no impact or minimal impact on the market.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1		
	2		
	3		

Nodal Protocol Revision Request

	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Completion of Nodal Protocols.*	
	2	*Synchronization of remaining zonal Protocol sections with the Nodal Protocols.*	
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Market Segment	Not applicable.

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Comments

A new Definitions Section has been added to the beginning of Section 18 for defined terms used only in this Section. Either definitions will need to be added for terms that are not defined but are capitalized throughout Section 18 or such terms should be made lower case if stakeholders choose not to define them.

Proposed Protocol Language Revision

ERCOT Nodal Protocols
Section 18: Load Profiling

~~July~~ xxxxx 1, 200~~7~~8

(Upon Texas Nodal Market Implementation)

18 LOAD PROFILING

SECTION 18 DEFINITIONS

The following definitions are supplied for terms used only in this Section.

Load Profile Models
Processes that use analytical modeling techniques to create Load Profiles.

Mandatory Installation Threshold
Mandatory Installation Threshold is a peak demand greater than 700 kW (or 700 kVA).

Non-Metered Load or Group
Load that is not required to be metered by applicable distribution or transmission tariff.

SECTION 18 ACRONYMS

The following acronyms are supplied for terms used only in this Section.

TOUS Time Of Use Schedule

18.1 Overview

(1) The ERCOT retail market requires a ~~fifteen (~~15~~)~~ minute ~~s~~Settlement ~~i~~Interval, yet the vast majority of Customers do not have the metering necessary to measure their consumption at this level of granularity. Load Profiling provides a cost-effective way of estimating ~~fifteen (~~15~~)~~ minute ~~l~~Load for these Customers, enables the accounting of their energy usage in the market S~~s~~ettlement process, and allows the participation of these Customers in the retail market.

(2) This S~~s~~ection details how Load Profiling will be implemented in ERCOT.

18.2 Methodology

(1) ERCOT ~~will~~has develop~~ed~~ Load Profiles for both non-interval metered L~~l~~oads and Non-Metered Loads. A Load Profiling ~~M~~methodology is the fundamental basis on which Load Profiles are created. The implementation of a Load Profiling ~~M~~methodology may require statistical ~~S~~sampling, engineering methods, econometric modeling, or other approaches.

(2) The following Load Profiling methods ~~will be~~are used~~ for market open~~:

Type of Load	Load Profiling Methodology

Non-~~I~~interval ~~M~~metered	Adjusted ~~S~~static ~~M~~models
Non-Metered	Engineering ~~E~~estimates

(3) Load Profiles ~~will~~have also been developed for Interval Data Recorders (IDRs) for use in ~~s~~Settlements when actual IDR data is not available. All Load Profiles ~~will~~shall conform to the ERCOT-defined Settlement Interval length.

(4) Any change from one methodology to another will require approval of the Technical Advisory Committee (TAC), without the necessity of complying with the procedures in Section 21, Process for Protocols Revision. TAC shall establish the implementation date for approved changes, ~~as TAC deems appropriate,~~ recognizing the magnitude of the impacts on Market Participants.

18.2.1 Guidelines for Development of Load Profiles

In developing Load Profiles, ERCOT shall strive to achieve an optimal combination of the following:

(~~1~~a) Give no unfair advantage to any Entity;

(b~~2~~) Maximize usability by minimizing the total number of Load Profiles without compromising accuracy and cost effectiveness;

(c~~3~~) Minimize the Load Profiles' contribution to Unaccounted For Energy (UFE) over all Settlement Intervals, paying particular attention to higher cost periods;

(d~~4~~) Reflect reasonably homogenous groups, with respect to L~~l~~oad shape and likely supply costs;

(e~~5~~) Develop Load Profiles that are distinctly different;

(f~~6~~) Develop Load Profiles for areas with incomplete L~~l~~oad data utilizing data from other sources, taking into account similarities and differences in ~~l~~Load;

(g~~7~~) Accommodate Time ~~o~~Of Use (TOU) rate classes;

[PIP 106: Current system design does not allow for controlled L~~l~~oads or other similar pricing schemes. When the functionality is included in system design, item number (7) above will be replaced with the following:]

(g~~7~~) Accommodate Time ~~o~~Of Use (TOU) rate classes, controlled L~~l~~oad classes, and other similar pricing schemes;

(h~~8~~) Use the most accurate L~~l~~oad research data available; and (i~~9~~) Develop Load Profiles based on readily identifiable parameters that are not subject to frequent change.

18.2.2 Load Profiles f~~F~~or Non-Interval Metered Loads

Load Profiles for non-interval metered ~~l~~Loads ~~will be~~are created using statistical models developed from appropriate ~~l~~Load research sample data. These models are referred to as ~~"~~adjusted static~~."~~. These model equations ~~will~~ relate daily Settlement Interval L~~l~~oad patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times ~~will~~are also ~~be~~ employed.

[PRR478: Replace Section 18.2.2 above with the following upon system implementation:]

~~For market open,~~ (1) Load Profiles for non-interval metered ~~l~~Loads ~~we~~are created using statistical models developed from appropriate ~~l~~Load research sample data. These models are referred to as ~~"~~adjusted static~~."~~. These model equations relate daily Settlement Interval Load patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times are also employed.

~~Following market open, n~~(2) New Load Profile segments may be introduced as needed. After these Load Profile segments receive final approval under the provisions of the Load Profiling Guide (LPG)~~s~~, Section 12, Request for Profile Segment Changes, Additions, or Removals, they may be settled by using appropriately sized and representative lagged dynamic samples or adjusted static models. The decision to use a lagged dynamic sample or adjusted static model shall be based on the judgment of ERCOT's Load Profiling Department, subject to TAC approval.

18.2.3 Load Profiles for Non-Metered Loads

Load Profiles ~~will be created~~ for Non-Metered Loads, e.g. streetlights, traffic signals, security lighting, billboards, and parking lots~~, etc. These Load Profiles will be~~ are created ~~by~~ using engineering estimates based on known criteria, such as hours of operation, with appropriate variation in sunrise/sunset times~~ when suitable~~. Transmission Service Providers (TSPs) and/or Distribution Service Providers (~~T~~DSP~~s~~) are responsible for providing monthly consumption (kWh) for ~~n~~Non-~~m~~Metered Electric Service Identifiers (ESI IDs).

18.2.4 Generic Load Profiles for Interval Data Recorders

(1) Generic or default Load Profiles will be developed for IDRs. These profiles will only be used when no historic Customer-specific interval data is available for S~~s~~ettlements. The ~~"~~adjusted static~~"~~ methodology will be used to create these Load Profiles.

(2) For details on the method to estimate IDR data for ~~s~~Settlement purposes, refer to Section 11, Data Acquisition and Aggregation.

~~*18.2.5 Reserved*~~

18.2.~~6~~5 Identification of Weather Zones and Load Profile Types

ERCOT, in coordination with the appropriate ~~ERCOT~~ TAC subcommittee, will identify Weather Zones and Load Profile Types based on an analysis of the L~~l~~oad research data, weather data, effects of power price changes from interval to interval, and sunrise/sunset data.

18.2.~~7~~6 Daily Profile Creation Process

ERCOT will maintain Load Profile ~~m~~Models to create profiles for the target ~~s~~Settlement day (backcast) and three ~~(3)~~ days following the current day (forecast). ERCOT will automatically collect actual weather conditions and weather forecasts to enable the creation of the Load Profiles. ERCOT will maintain sunrise/sunset information for creating Load Profiles that require these parameters.

[PRR478: Replace Section 18.2.7 above with the following upon system implementation:]

ERCOT shall maintain adjusted static models for Load Profiles and any representative samples for lagged dynamic Load Profiles to create Load Profiles for the target ~~s~~Settlement day (backcast) and three ~~(3)~~ days following the current day (forecast). ERCOT will automatically collect actual weather conditions and weather forecasts to enable the creation of the Load Profiles. ERCOT will maintain sunrise/sunset information for creating Load Profiles that require these parameters.

18.2.~~8~~7 Maintenance of Samples and Load Profile Models

ERCOT, in coordination with TSPs and/or DSPs, shall periodically monitor, review, and maintain the validity and accuracy of the L~~l~~oad research samples and the Load Profiling models. ERCOT shall take the necessary action to alleviate any situations whereby Load Profiles are no longer representative.

18.2.7~~8~~.1 Sample Maintenances

(1) ERCOT will review L~~l~~oad research sample validity (e.g. difference-of-means test) at the following times:

(a~~1~~) -Aat least annually~~every year~~, and (b~~2~~) W~~w~~hen discrepancies (such as excessive UFE) or disputes warrant.

(2) ~~When ERCOT implements its own lLoad research Sampling,~~ ERCOT will monitor and review this ~~S~~sampling in accordance with ERCOT Protocols, the Load Profiling Guide (LPG) and the most current Association of Edison Illuminating Companies (AEIC) Load Research manual.

~~(3) ERCOT may request the TDSPs to submit available class lLoad research data and supporting sample IDR data to ERCOT as frequently as every six (6) months, or at other times as situations warrant.~~

18.2.7~~8~~.2 Model Maintenance~~s~~

ERCOT shall monitor the applicability of the Load Profiling models by comparing all available actual ~~IDR~~interval data samples with estimates generated from the profile model by interval for the same time period. Should these comparisons reveal significant discrepancies, ERCOT should take appropriate action and coordinate with the appropriate ~~ERCOT~~ TAC subcommittee ~~(UFE analysis function), if necessary~~.

18.2.8~~9~~ Adjustments and Changes to Load Profile Development

(1) ERCOT and the appropriate ~~ERCOT~~ TAC subcommittee will conduct an ongoing evaluation of the current Load Profiling ~~M~~methodology. Together they will determine whether appropriate changes to the methodology should be made or whether another approach or combination of approaches is warranted. Any Market Participant may request a review of the Load Profiling ~~M~~methodology. A change from one Load Profiling ~~M~~methodology to another must be approved by TAC, as provided in Section 18.2, Methodology.

(2) Any Market Participant may petition ERCOT for adjustments to the existing Load Profiles and for development of new Load Profiles. The Market Participant making the request shall submit their proposal in writing to ERCOT. ERCOT will post to the Market Information System (MIS) Public Area the request and respond to such requests within ~~sixty (~~60~~)~~ days. ERCOT shall coordinate with the appropriate ~~ERCOT~~ TAC subcommittee for each change request. ERCOT shall strive to make the necessary changes within a reasonable period of time.

(3) ERCOT, in coordination with the appropriate ~~ERCOT~~ TAC subcommittee, may make changes to existing Load Profiles and establish additional Load Profiles. All changes to Load Profiles shall adhere to these Protocols. When additional Load Profiles are established, ERCOT shall evaluate the impact on existing Load Profiles and associated ~~l~~Load research samples.

(4) A Market Participant may submit a request to ERCOT for conditional approval of a new Load Profile segment following the approval process as specified in the ~~Load Profiling Guides,~~ LPG Section 12, Request for Profile Segment Changes, Additions, or Removals.

In conjunction with this request, ERCOT staff shall specify the requirements for additional Load research sampling and shall define specific and objective criteria to be met by the analysis of this Load research data to meet the requirements for final approval. Provided the request for conditional approval has received the appropriate ERCOT committee approval and ERCOT staff determines the specified criteria are met, the request shall be granted final approval. If ERCOT staff determines the specified criteria are not met, the request shall be denied.

(5) Section 9.9, Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment, describes the process for compensating the originator of a profile segment change request by Retail Electric Providers (REPs) wishing to subscribe to the profile segment.

(6) ERCOT shall give at least ~~one hundred fifty (~~150~~)~~ days notice to all Market Participants prior to market implementation of any change in Load Profile Methodology, existing Load Profiles, or when any additional Load Profiles are developed. This notice shall include a Load Profile change implementation timeline, which specifies dates on which key events during the Load Profile change process will take place. Upon any change in Load Profile Types, TSPs and/or DSPs shall send any revised ~~ESI~~ Load Profile ID assignments required by the change to the registration system within the implementation timeline. After the new Load Profile(s) becomes available, changes to Load Profile Types will be effective on the next meter read date for each ESI ID.

(7) If one or more Load Profiles require changes to reduce excessive UFE, as determined by the appropriate ~~ERCOT~~ TAC subcommittee, TAC may provide a shorter notice period and implementation date, than otherwise provided herein, for such required changes to Load Profiles. If the Load Profile Methodology requires changes to reduce excessive UFE, as determined by the appropriate ~~ERCOT~~ TAC subcommittee, TAC may provide an expedited notice period and implementation date. TAC may require the standard Load Profile revision process follow such expedited revisions for long-term resolution.

18.2.~~10~~9 Special Requirement for Profiling Sample Points

~~(1)~~ When a Premise ~~has an Interval Data Recorder (IDR) installed~~is used as part of a L~~l~~oad research sample used for Load Profiling, and that Premise or that Premise's Competitive Retailer (CR) elects to use its interval data for S~~s~~ettlement purposes, it will be necessary to replace that Premise in the sample. It will be incumbent on ERCOT to coordinate this type of change with the TSP and/or DSP, if appropriate.

~~(2) A Premise cannot be sampled for both a Load Profiling program and a special application program.~~

18.2.1~~1~~0 Responsibilities for Sampling in Support of Load Profiling

18.2.1~~1~~0.1 ERCOT Sampling Responsibilities

ERCOT is responsible for the development and maintenance of Load Profiles used in the ERCOT market. ERCOT shall follow the Load Profiling and Load Research rules and procedures as specified in the Public Utility Commission of Texas (PUCT) rules.

18.2.1~~1~~0.2 Transmission Service Provider and/or Distribution Service Provider Sampling Responsibilities

(1) The TSP's and/or DSP~~s~~'s Load research data are critical for Load Profile development by ERCOT~~ from market open through implementation of an ERCOT Load research program~~. TSPs and/or DSPs, other than Non-Opt~~-~~-In Entities (NOIE), shall provide available Load research data when requested by ERCOT.

(2) The TSPs and/or DSPs, other than ~~Non-Opt-In Entities~~NOIEs, shall provide ERCOT at least one ~~(1) ~~year's notice of any significant change in the status of the TSP's and/or DSPs' Load research programs.

(3) TSPs and/or DSPs shall address the appropriate ~~ERCOT ~~TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

(4) TSPs and/or DSPs shall follow the rules and procedures as specified in PUCT rules.

(5) ERCOT may request from TSPs and/or DSPs, and such TSPs and/or DSPs shall provide, the most current Load research data reasonably available to aid in the development or refinement of Load Profile ~~m~~Models, subject to Section 18.2.~~9~~8, Adjustments and Changes to Load Profile Development.

18.3 Posting

ERCOT will make available to Market Participants the following information in a timely manner, subject to confidentiality agreements, proprietary arrangements, and Public Utility Commission of Texas (PUCT) rules and regulations.

18.3.1 Methodology Information

A complete description of all supporting models, documentation and data used in preparation of Load Profiles will be made available on the Market Information System (M~~arket Information System~~IS) Public Area, including:

(a~~1~~) The historic ~~l~~Load data used to create the Load Profiles;~~;~~

(b~~2~~) Average interval accuracy of each Load Profiling model;~~;~~

(c~~3~~) Weather information;~~;~~

(d~~4~~) Sunrise/sunset information;~~;~~

(e~~5~~) Updates of Transmission Service Provider (TSP) and/or Distribution Service Provider (~~T~~DSP) ~~l~~Load research data as it becomes available to ERCOT;~~;~~ and

(f~~6~~) Any other data used for Load Profile development.

18.3.2 Load Profiling Models

ERCOT will make available the models used to produce the forecast and backcast profiles for the S~~s~~ettlement process. The Load Profile ~~m~~Models shall be accessible via the M~~arket Information System~~IS Public Area in a downloadable format.

18.3.3 Load Profiles

(1) ERCOT will publish Load Profile data from the profile creation process, in accordance with Section 18.2.~~7~~6, Daily Profile Creation Process to the Market Information System and through the common API. Load Profile data will be made available to Market Participants for a period of two ~~(2)~~ years.

(2) ERCOT will post to the M~~arket Information System~~IS Public Area by 1000 A.M. Central Prevailing Time each Business Day forecasted Load Profiles for the three ~~(3)~~ following days for each Load Profile Type and Weather Zone. Backcast profiles for each Load Profile Type and Weather Zone will be available by 1000 A.M. Central Prevailing Time of the second ~~(2nd)~~ Business Day following the backcast day. No data will be provided that will allow identification of individual Customers.

18.4 Assignment of Load Profile ID

Each Electric Service Identifier (ESI ID) is required to be associated with an appropriate Load Profile ID. This section details the process of assigning a Load Profile ID to each ESI ID.

18.4.1 Development of Load Profile ID Assignment Table

ERCOT shall develop a cross-reference table of all Load Profile ID used in the ERCOT market. The table shall clearly state class relationship to Load Profile Type. This information shall be made accessible, on the Market Information System (MIS) Public Area, to all Market Participants. The cross-reference information shall be compiled and expressed in clear, unambiguous language, and in a manner that will minimize Load Profile ID assignment disputes.

~~***18.4.2 Reserved***~~

18.4.~~3~~2 Load Profile ID Assignment

(1) ERCOT and the appropriate ~~ERCOT~~ Technical Advisory Committee (TAC) subcommittee shall review the Load Profile ID assignment process on an annual basis, make recommendations for enhancements, and evaluate the integration of the validation and assignment processes.

(2) Any Market Participant may request temporary changes to the yearly process for assigning and validating Load Profile IDs to address unusual circumstances. Such requests shall be submitted to the appropriate ~~ERCOT~~ TAC subcommittee. If the request is approved by the ~~ERCOT~~ TAC subcommittee, it shall then be submitted to the TAC. Such requests, if approved by the TAC, shall be in effect only for the requested year.

(3) Should there be any change in Load Profile ID assignment to any ESI ID, it will be the responsibility of the Transmission Service Provider (TSP) and/or Distribution Service Provider (~~T~~DSP) to submit those changes to ERCOT.

18.4.~~4~~3 Validation of Load Profile Type and Weather Zone Assignments

In this S~~s~~ection validation shall mean performing checks to ensure correct assignment of ~~ESI IDs to~~ Load Profile Types and Weather Zones to ESI IDs.

18.4.~~4~~3.1 Validation Tests

~~This section refers to validation of the assignment of Load Profile Type and Weather Zone to ESI IDs.~~

(1) Validation tests of Load Profile Type and Weather Zone assignments, at a minimum, will occur at the following times: initial Load Profile ID assignment, when a change is made in the Load Profile Type or Weather Zone assignment, and at least one time per year.

(2) ERCOT may utilize a sampling method for Load Profile Type assignment validation and when a change is made in the Load Profile ID assignment.

(3) ERCOT shall validate the assignment of the Weather Zone component of the Load Profile ID for all ESI IDs.

(4) ERCOT shall perform validation tests of the initial Load Profile Type and Weather Zone assignments of each TSP and/or DSP. Samples of assignments from the Residential and Business Profile Groups will be randomly drawn from each TSP's and/or DSP's population of profiled ESI IDs. If the assignment validation failure rate for any of these samples exceeds parameters specified in the Load Profiling Guide (LPG)~~s~~, ERCOT may request an audit of the corresponding TSP's and/or DSP's Load Profile ID assignment

processes and systems at the expense of the TSP and/or DSP. ERCOT may require TSPs and/or DSPs that fail sample Load Profile Type or Weather Zone assignment validations and/or audits to resubmit Load Profile ID assignments for all ESI IDs in their service territory.

(5) Details of all validation tests will be specified in the ~~Load Profiling Guide~~LPG~~s~~. Competitive Retailers (CR) may dispute a Load Profile ID assignment through the ERCOT ~~s~~Settlement dispute process, as described in Section 9.5, Settlement and Billing Process, in conjunction with the ~~Load Profiling Guide~~LPG~~s~~.

(6) TSPs and/or DSPs shall change the assignment of a Load Profile ID ~~for the single ESI ID~~ based on ~~an outcome of~~ a dispute outcome finding in favor of a ~~Competitive Retailer~~CR. If required to change an assignment, TSPs and/or DSPs must correct the assignment in their system and the ERCOT Customer registration system within three ~~(3)~~ Business Days.

18.4.~~4~~3.2 Correction Procedure

(1) TSPs and/or DSPs are responsible for investigating each ESI ID identified by ERCOT as having a potentially incorrect Load Profile ID assignment. Each TSP and/or DSP shall work closely and promptly with ERCOT during the correction procedure, which is detailed in the ~~Load Profiling Guide~~LPG~~s~~.

(2) Market Participants may dispute an assignment through the ERCOT S~~s~~ettlement dispute process, described in Section 9.5~~, Settlement and Billing Dispute Process, of these Protocols~~.

18.4.3.~~.~~4~~5~~ Assignment of Weather Zones to Electric Service Identifiers~~ESI IDs~~

(1) TSPs and /or DSPs will assign each ESI ID to a Weather Zone, based on service address ~~zip~~ ZIP code.

(2) ERCOT will post to the MIS Public Area a mapping of a Weather Zone to appropriate Customer registration element used in assigning Weather Zones.

18.5 Additional Responsibilities

This S~~s~~ection addresses responsibilities for Load Profiling not specified in other s~~S~~ections of the Protocols.

18.5.1 ERCOT Responsibilities

ERCOT will develop, administer, and maintain Load Profiles in accordance with these Protocols. Disputes related to the accuracy or appropriateness of Load Profiles shall be handled in accordance with Section 9.5, Settlement and Billing Dispute Process.~~, Settlement and Billing Dispute Process~~.

18.5.2 Transmission Service Provider and/or Distribution Service Provider Responsibilities

Transmission Service Providers (TSPs) and/or Distribution Service Providers (~~T~~DSPs) shall use the appropriate ~~ERCOT~~ Technical Advisory Committee (TAC) subcommittee as a forum for their input in the development and refinement of Load Profiles.

18.5.3 Competitive Retailer Responsibilities

(1) Competitive Retailers (CRs) shall use the appropriate ~~ERCOT~~ TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

(2) C~~ompetitive Retailer~~Rs shall be responsible for reviewing any assignment of Load Profiles to Electric Service Identifiers (ESI IDs) they represent.

18.6 Installation and Use of Interval Data Recorders

18.6.1 Interval Data Recorder ~~(IDR)~~ Installation and Use in Settlement

(1) Interval Data Recorder (IDR) Mandatory Installation Threshold: IDRs shall be installed and utilized for S~~s~~ettlement of Premises having either:

(a~~.~~) A peak demand greater than 1000 kW (or 1000 kVA), or

(b~~.~~) Service provided at transmission voltage (above 60 kV).

As of October 1, 2005, the IDR Mandatory Installation Threshold shall be a peak demand greater than 700 kW (or 700 kVA) and all meter changes shall be completed by the later of April 30, 2006 or within ~~one hundred and twenty (~~120~~)~~ consecutive days of the Competitive Retailer (CR) being notified that the IDR Mandatory Installation Threshold has been met, or

(2) A ~~Competitive Retailer~~CR, upon a Customer's request or with a Customer's authorization, may have an IDR installed and used for ~~s~~Settlement purposes at any associated Premise outside the IDR Mandatory Installation Threshold. Except as stated in item (4) of this Section, IDRs in place or installed after September 1, 1999 shall be used for ~~s~~Settlement. Once an IDR is installed on a Premise and used for ~~s~~Settlement purposes, the given Premise shall continue to be settled with its interval data, except as stated in Section~~s~~ 18.6.~~7~~6, Interval Data Recorder Optional Removal Threshold. If a Customer or CR requests installation of an IDR meter, the same Customer may not request removal of the IDR meter for a period of ~~twelve (~~12~~)~~ consecutive months following such installation.

(3) All Non-Metered Loads such as street lighting, regardless of the aggregation level, shall not be required to install IDRs under the IDR Mandatory Installation Threshold. These Loads shall be settled using Load Profiles.

(4) For Premises not subject to the IDR Mandatory Installation Threshold in item (1) of this Section:

(a) IDRs installed at the request of ERCOT, a Transmission Service Provider (TSP) and/or Distribution Service Provider (~~T~~DSP), a M~~m~~unicipally Owned Utility (MOU), or an Electric C~~c~~ooperative (EC) for ~~l~~Load research, rate/tariff design calculation, coincident demand calculation, or Load Profiling purposes shall be exempt from the requirement to use an IDR for ~~s~~Settlement purposes;~~:~~ or

(b) IDRs previously used specifically for separating Non-Opt-In Entity (NOIE) Load from competitive Load shall be exempt from the requirement to use an IDR for r~~R~~etail Customer settlement purposes, provided that the IDR meter has been removed within ~~one hundred and twenty (~~120~~)~~ consecutive days after the NOIE has fully implemented Customer Choice. IDR meters used for NOIE separation that do not meet the IDR Mandatory Installation Threshold shall not be used for retail Customer settlement purposes.

(5) For IDR installation procedures reference Section 10.2.2, TDSP Metered Entities.

(6) TSPs and/or DSPs responsible for any Load transfer schemes between ERCOT and n~~N~~on-ERCOT Regions shall install IDR metering capable of measuring the Load served during the period the Load transfer is implemented.

18.6.2 Interval Data Recorder Administration Issues

ERCOT shall produce a report informing the appropriate Market Participants of profiled Premises that have become subject to the provisions of item (1) of Section 18.6.1~~(1)~~, Interval Data Recorder Mandatory Installation Threshold. ERCOT shall put in place a system to track Market Participants' timely adherence to this requirement. This report shall be posted to the Market Information System (MIS) Private Area.

18.6.3 Adherence to Interval Data Recorder Requirements

M~~unicipal~~OUs~~ Entities~~ and E~~lectric Cooperative~~Cs~~ Entities~~ that opt-in to Customer Choice must install IDR meters at all Premises subject to the IDR Mandatory Installation Threshold for metering prior to the effective date of their participation in the testing and integration requirements of ERCOT S~~s~~ystems for Customer Choice.

18.6.4 Technical Requirements

(1) Regardless of data retrieval method, interval data shall be provided on a schedule that supports the requirements of final S~~s~~ettlement (typical monthly billing cycle).

(2) Interval data that is provided for S~~s~~ettlement shall be consistent with the ERCOT defined Settlement Interval.

~~IDRs used for settlement shall meet technical metering requirements defined in the Load Profiling Guides.~~

~~*18.6.5 Future Requirements for IDRs*~~

~~ERCOT and the appropriate ERCOT TAC subcommittee shall evaluate the impact of the IDR Mandatory Installation Threshold as defined in this Section for possible revision prior to the introduction of competitive metering services to the market on January 1, 2004.~~

18.6.~~6~~5 Peak Demand Determination for Non-Interval Data Recorder Premises

(1) For the purpose of determining the peak D~~d~~emand level for the IDR Mandatory Installation Threshold in Section 18.6.1, Interval Data Recorder ~~(IDR)~~ Installation and Use in Settlement, the D~~d~~emand will be determined in accordance with Public Utility Commission of Texas (PUCT) rulemaking or through a consensus process with ERCOT and Market Participants. In the absence of a clear definition of peak D~~d~~emand in the ~~"price to beat"~~PUCT rulemaking, the following application shall be used in determining the peak ~~d~~Demand level for IDR Mandatory Installation Threshold in Section 18.6.1~~, Interval Data Recorder (IDR) Installation and Use in Settlement~~.~~:~~

(2) A Premise (ESI ID) has a peak ~~d~~Demand greater than the applicable level in Section 18.6.1~~, Interval Data Recorder (IDR) Installation and Use in Settlement~~, above, when measured in any two ~~(2)~~ billing months of the most recent ~~twelve (~~12~~)~~ month period. C~~ompetitive Retailers~~Rs may dispute an IDR assignment through the ERCOT S~~s~~ettlement dispute process, described in Section 9.14~~5~~, Settlement and Billing Dispute Process.

(3~~2~~) ERCOT shall be responsible for receiving and storing ~~d~~Demand information necessary for determining mandatory IDR installations.

18.6.~~7~~6 Interval Data Recorder Optional Removal Threshold

(1) The CR, upon a Customer's request or with a Customer's authorization, may request, in accordance with PUCT rules and regulations, removal of an IDR at the Customer's Premise unless service to the Premise is provided at transmission voltage (above 60 kV). However, once the Customer's D~~d~~emand at the Premise ~~either~~ meets ~~or exceeds~~ the IDR

Mandatory Installation Threshold identified in item (1) of Section 18.6.1, the IDR will no longer qualify for removal.

(2) The "IDR Optional Removal Threshold" for a Premise is established as follows:

(~~1~~a) ~~f~~For an existing Customer, where the Load at the Premise has ~~never~~not exceeded the IDR Optional Removal Threshold of ~~one hundred and fifty (~~150~~)~~ kW (kVA) during the most recent ~~twelve (~~12~~)~~ consecutive months unless the existing Customer requested or authorized installation of an IDR pursuant to item (2) of Section 18.6.1~~(2)~~ in which case the existing Customer may not request removal of the IDR for a period of ~~twelve (~~12~~)~~ consecutive months following such installation~~;~~; or

(~~2~~b) ~~f~~For a new Customer m~~M~~ove-i~~I~~n, where the request is communicated to the CR within ~~one hundred and twenty (~~120~~)~~ consecutive days of the m~~M~~ove-i~~I~~n provided the new Customer's Demand at the Premise has remained below the IDR Mandatory Installation Threshold between the m~~M~~ove-i~~I~~n date and the date the request is received, and that meter readings covering at least ~~forty five (~~45~~)~~ consecutive days of usage at the Premise have been registered for the new Customer.

(3) Once an IDR has been removed at a Premise by request, an IDR may not be reinstalled at that Premise for a period of ~~twelve (~~12~~)~~ consecutive months following such removal, unless a change in Customer(s) has taken place at that Premise during the ~~twelve (~~12~~)~~ month period or unless the IDR Mandatory Installation Threshold pursuant to item (1) of Section 18.6.1~~(1)~~ has been met. Removal or re-installation of an IDR is subject to applicable tariff charges.

18.7 Supplemental Load Profiling

ERCOT and the appropriate ~~ERCOT~~ Technical Advisory Committee (TAC) subcommittee recognize the possible need to accommodate Load Profiling for programs or pricing schemes that encourage a ~~d~~Demand response to price in the retail market. Accordingly, Load Profiling methods other than adjusted static methodology are necessary.

18.7.1 Load Profiling of Time-of-Use Metered Electric Service Identifier~~ESI ID~~

18.7.1.1 Overview

(1) A Time Of Use (TOU) meter is a programmable electronic device capable of measuring and recording electric energy in pre-specified time periods. For Load Profiling purposes this definition does not include Interval Data Recorders (IDRs). For additional information regarding TOU, reference the Load Profiling Guide~~s~~.

(2) The ERCOT Data Aggregation and Settlement systems must be able to ~~collect~~accept and handle TOU meter data. The profiling of P~~p~~remises participating in TOU programs requires TOU meter reads so that consumption can be distributed within the appropriate time periods.

18.7.1.2 Methodology ~~F~~for Load Profiling of Time Of Use ~~(TOU)~~

The selected technique for generating profiles for TOU Premises is described as follows:

(~~1~~a) Each TOU Premise is assigned to a standard Load Profile Type.

(b~~2~~) Upon agreement between the Competitive Retailer (CR) and Transmission Service Provider (TSP) and/or Distribution Service Provider (~~T~~DSP), a Time-of-Use Schedule (TOUS) is submitted by the TSP and/or DSP to the ERCOT Data Aggregation System (DAS), which identifies the TOU period associated with each Settlement Interval. The number of TOU periods is determined by the number of periods for which the meter will capture kWh. These periods may include on-peak, off-peak, and shoulder periods. The DAS shall collect and maintain the attributes of the TOUS (e.g. start and stop time, day of the week, and season~~, etc~~.).

(~~3~~c) C~~ompetitive Retailers~~Rs shall communicate to TSPs and/or DSPs their Electric Service Identifiers (ESI IDs) associated with the proper TOUS.

(d~~4~~) The TSP and/or DSP shall communicate all TOUSs to DAS so that proper TOUS identification for each Premise will occur in the ERCOT ~~central database~~System.

(e~~5~~) The ERCOT DAS shall use the standard Load Profile assigned to each TOU Premise and scale the energy for each TOU period in the Load Profile so that it is equal to the metered energy (kWh) for the TOU period.

(f~~6~~) TOU Load Profiling will not use TOU D~~d~~emand values.

18.7.1.3 Collection of Time-Of-Use Meter Data

TSPs and/or DSPs will be responsible for providing the meter reads necessary to support TOUS available in their service territory. The ERCOT DAS shall ~~collect and~~ handle multiple TOU reads~~ for each Settlement Interval~~. These ~~Settlement Intervals~~TOU reads may include on-peak, off-peak, and shoulder periods.

18.7.1.4 Availability of Time Of Use Schedules

The availability of TOU-~~S~~Sschedules will be dependent on the following:

(~~1~~a) For TSP and/or DSP service territories with TOU tariffs in effect prior to December 31, 2000, all Competitive Retailers will be able to offer the TOU ~~schedule~~Ss associated with those tariffs; and ~~.~~

(b~~2~~) ~~Within every TDSP service territory, additional TOUS shall be implemented if approved by the PUCT.~~ The implementation of any new or modified TOUS would be subject to the ERCOT and Texas Standard Electronic Transaction (Texas SET) change control process.

18.7.1.5 Post Market Evaluation

Starting at the first completed ~~s~~Settlement cycle, ERCOT and the appropriate ~~ERCOT~~ TAC subcommittee shall periodically review the selected profiling technique of TOU ESI IDs for accuracy, and validity. They may recommend enhancements, modifications, or a complete replacement of the technique.

18.7.2 Load Profiling of ~~ESI IDs~~Electric Service Identifier Under Direct Load Control

This S~~s~~ection is reserved for future implementation of Direct Load Control (DLC).

[PIP 106, PRR385, and PRR469: Current design does not provide for DLC settlement functions. When DLC Profiles are implemented, insert all of section 18.7.2 in this reserved section.]

18.7.2.1 Overview

(1) Direct Load Control (DLC) programs require the installation of control devices on selected end-use equipment for the purposes of reducing energy consumption during Competitive Retailer selected time intervals. It is recognized that these programs may result in altered ~~l~~Load shapes that could no longer be represented by the Load Profile M~~m~~odels that will be used for non-controlled L~~l~~oads.

(2) The Load Profiling Guide~~s~~ (LPG) shall be referenced for details regarding the implementation of DLC in the ERCOT market.

18.7.2.2 ~~Market Open~~Direct Load Control Profiling Methodology

~~For market open, t~~The technique for profiling Premises participating in DLC programs will be the use of a ~~r~~Representative IDR (RIDR) profile. This approach consists of implementing a statistically representative ~~l~~Load research sample on the DLC population. The sample data is then used to develop the ~~representative IDR (~~RIDR~~)~~ for profiling these Premises.

18.7.2.2.1 Sample Design for the Representative Interval Data Recorder Profile

All samples, intended for use in developing DLC RIDR profiles, shall comply with the following rules:

(a) Samples should be selected from the active DLC program population, in a statistically random fashion;~~.~~

(b) The final installed ~~S~~sample ~~S~~size shall be augmented from the original ~~S~~sample ~~S~~size to include a ten percent (10%) over-sampling margin;~~.~~

(c) The original ~~S~~sample ~~S~~size shall be determined to achieve and maintain a minimum ~~ninety percent (~~90%~~)~~ confidence level, and a minimum plus or minus ten percent (~~—~~±10%) accuracy, through each of the ~~twelve (~~12~~)~~ calendar months, and regardless of the selected sampling variable (e.g., monthly kWh, monthly peak kW);~~.~~

(d) The ~~S~~sample ~~D~~design shall be fully documented and made available to ERCOT, the appropriate ~~ERCOT~~ TAC subcommittee, and the PUCT, when requested;~~.~~

(e) The ~~S~~sample ~~D~~design, selection and maintenance shall adhere to the most recently published AEIC Load Research Manual;~~.~~

(f) The data processing, validation, editing, and estimation shall be performed according to Section 10.11, Validation, Editing and Estimating of Meter Data;~~, of these Protocols.~~

(g) All installed sample IDRs shall meet or exceed the ERCOT minimum specifications for IDR metering;~~.~~

(h) The sample statistical validity shall be verified every calendar year, and deficiencies shall be corrected as soon as practicable; and~~.~~

(i) The anonymity of the DLC sample sites shall be maintained by all parties.

18.7.2.2.2 Roles and Responsibilities of Market Participants

(1) The proper implementation of the RIDR methodology requires ERCOT, Competitive Retailers, T~~D~~SPs and/or DSPs and their respective third party agents to adhere to the responsibilities in Section 18.7.2.2, ~~Market Open~~Direct Load Control Profiling Methodology.

(2) Furthermore, ERCOT, TSPs and/or DSPs and their third party agents are the only Entities

that shall know the location or identity of the RIDR sample sites.

18.7.2.2.3 ERCOT Direct Load Control Responsibilities

(1) ERCOT is responsible for evaluating and approving all requests for Profile development of DLC programs. The request shall include information necessary to validate the ~~S~~sample ~~D~~design and verify the installation of both DLC devices and communication equipment.

(2) ERCOT shall maintain the database used to identify the population of ESI IDs participating in all DLC programs. Furthermore, ERCOT shall facilitate the registration of DLC programs in the D~~ata Aggregation System~~AS.

(3) ERCOT or its designated third party agent is responsible for all ~~S~~sample ~~D~~design, implementation, monitoring, and validation of DLC program ~~l~~Load research samples. ERCOT shall adhere to AEIC L~~l~~oad research practices in maintaining the statistical validity of the sample.

(4) ERCOT may contract with a third party agent, selected in cooperation with the CR, to install the required number of sample IDRs, when installation of IDR metering service becomes competitive.

(5) ERCOT may contract with a third party agent, selected in cooperation with the CR, to collect and validate the sample data, in accordance to AEIC L~~l~~oad research practices, and in accordance with Section 10.11, Validation, Editing and Estimation of Meter Data, when collection and validation of IDR data metering service becomes competitive.

(6) ERCOT shall arrange to redeploy to an alternate location, within the DLC population, any sample IDR installed on a Premise that is no longer served by the initial C~~ompetitive Retailer~~R, or on a Premise that no longer participates in the C~~ompetitive Retailer~~R's DLC program. ERCOT shall ensure that the redeployment of such sample points occurs within two ~~(2)~~ meter read cycles of the Customer switch date.

(7) When ERCOT has contracted with a third party agent to collect and provide sample IDR data, that agent shall validate, edit, and estimate the sample meter data in accordance with Section 10.11~~, Validation Editing and Estimation of Meter Data,~~ and transfer such data to ERCOT in an ERCOT-specified format and schedule.

(8) The ERCOT profiling system shall use the proper RIDR when profiling Premises participating in a DLC program, during the S~~s~~ettlement process. When actual RIDR data is not available for S~~s~~ettlements, the DLC Program Settlement methodology as described in the ~~Load Profiling Guides (~~LPG~~)~~, shall be employed.

(9) If the sample IDR data does not meet the data quality and availability standards, as detailed in the LPG, ERCOT shall provide a Settlement exception report, for Final and

subsequent Settlements, to the respective CR hosting the DLC program.

(10) ERCOT or its designated third party agent shall verify on a routine basis that the RIDR sample reflects the actual success/failure rate of the control devices in the DLC program population.

(11) ERCOT or its designated third party agent shall verify on a routine basis that the RIDR sample reflects the actual success/failure rate of the communication equipment in the DLC program population.

(12) ERCOT shall review existing DLC samples for compliance with the rules detailed in this Section. ERCOT may require adjustments to existing samples to meet these Protocols.

18.7.2.2.4 Competitive Retailer Direct Load Control Responsibilities

(1) C~~ompetitive Retailer~~Rs shall register their DLC programs according to the criteria specified in the LPG.

(2) C~~ompetitive Retailer~~Rs shall define their DLC programs, specify the controlled L~~l~~oads and describe the program's communication and control technologies.

(3) C~~ompetitive Retailer~~Rs shall pay for the installation, maintenance, and processing related to the L~~l~~oad research sample installed to support their DLC programs.

(4) C~~ompetitive Retailer~~Rs shall pay all costs associated with demonstrating the RIDR sample is a statistically valid representation of the DLC program population in terms of success/failure rate of the control devices and communication equipment.

(5) C~~ompetitive Retailer~~Rs may contract with a third party to administer the DLC program.

(6) C~~ompetitive Retailer~~Rs and their third party program administrator shall not attempt to discover the location or identity of sampled Premises used to develop the RIDR for their DLC programs. A C~~ompetitive Retailer~~R shall immediately notify ERCOT if it ascertains the location of any RIDR sample points. Any violation of this provision will result in a review by ERCOT of the RIDR used for DLC programs, which could result in the suspension of the DLC profile for use in ~~s~~Settlements. ERCOT may resettle the market for affected Settlement Intervals.

18.7.2.2.5 Transmission Service Provider and/or Distribution Service Provider Direct Load Control Responsibilities

(1) Each TSP and/or DSP, or its designated third party agent, shall install the required number of sample IDRs as determined by ERCOT, and shall maintain anonymity of the DLC sample sites.

(2) Each ~~TDSP~~TSP and/or DSP, or its designated third party agent, is responsible for

collecting, validating, editing, and estimating the sample meter data, in accordance to AEIC Load research practices, and in accordance with Section 10.11, Validation, Editing and Estimating of Meter Data.

(3) Each TSP and/or DSP, or its designated third party agent, shall provide validated, edited and estimated interval data to ERCOT for each sample IDR within its territory, and transfer such data to ERCOT in an ERCOT-specified format and schedule.

(4) Each TSP and/or DSP, upon ERCOT request, must provide to ERCOT the raw sample interval data for any DLC program offered within its territory.

18.7.2.3 Post Market Evaluation

Starting at the first completed settlement cycle, ERCOT and the appropriate ~~ERCOT~~ TAC subcommittee shall review the RIDR methodology for accuracy and validity on a regular basis. They may recommend enhancements, modifications, or a complete replacement of the methodology. In particular, ERCOT and the appropriate ~~ERCOT~~ TAC subcommittee shall review the profiling process of DLC programs, including their impact on non-DLC standard profiles~~, and make recommendations in view of competitive metering~~.

18.7.3 Other Load Profiling

ERCOT, in coordination with the appropriate ~~ERCOT~~ TAC subcommittee, may develop Load Profiles for particular Customer segments that ~~may~~ require special Load Profiling techniques similar in nature to TOU and DLC programs.~~ Details are specified in the Load Profiling Guides.~~

Nodal Protocol Revision Request

NPRR Number	110	NPRR Title	Section 20, Synchronization of Zonal Protocols
Date Posted		March 3, 2008	

Protocol Section Requiring Revision	Section 20, Alternative Dispute Resolution Process
Requested Resolution	Normal.
Revision Description	This Nodal Protocol Revision Request (NPRR) synchronizes zonal Protocol Section 20 with the current Nodal Protocols.
Reason for Revision	Synchronization of remaining zonal Protocol Sections with the Nodal Protocols.
Overall Market Benefit	Completion of Nodal Protocols.
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications (Yes or No, and summary of impact)	None.
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	

Quantitative Impacts and Benefits

Assumptions	1	*Synchronization changes are administrative in nature and should have no impact or minimal impact on the market.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**

Nodal Protocol Revision Request

	1		
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Completion of Nodal Protocols.*	
	2	*Synchronization of remaining zonal Protocol sections with the Nodal Protocols.*	
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

Sponsor	
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Market Segment	N/A

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Comments

A new Definitions Section has been added to the beginning of Section 20 for defined terms used only in this Section. Either definitions will need to be added for terms that are not defined but are capitalized throughout Section 20, or such terms should be made lower case if stakeholders choose not to define them.

Nodal Protocol Revision Request

Proposed Protocol Language Revision

ERCOT Nodal Protocols
Section 20: Alternative Dispute Resolution Procedure

October 1, 2004

(Effective Upon Texas Nodal Market Implementation)

20 ALTERNATIVE DISPUTE RESOLUTION PROCEDURE

SECTION 20 DEFINITIONS

The following definitions are supplied for terms used only in this Section.

Dispute Contact

Individual associated with Market Participant who is primary contact with ERCOT regarding pursuit of ADR request.

20.1 Applicability

(1) Except as provided for in this Section ~~20.1,~~, ~~Applicability,~~ this Alternative Dispute Resolution (ADR) ~~P~~procedure ~~(“ADR Procedure”)~~ shall apply to all disputes between ERCOT and one or more Market Participants or between two or more Market Participants relating to the application, implementation, and interpretation of, or compliance with~~,~~ these Protocols, any ~~other~~ approved market guide, or related Agreements. ERCOT need not participate as a party or facilitator in the ADR ~~P~~procedure ~~if none of the parties involved in the ADR Procedure~~. If any party in the ADR ~~P~~procedure, however, requests that ERCOT facilitate resolution of a dispute, then ERCOT shall do so. A party ~~must~~shall submit ~~The submission of~~ a covered dispute to these ADR ~~P~~procedures as~~is~~ a condition precedent to any right of any legal action on the dispute. This ADR ~~P~~procedure is of general applicability.

(2) When an Agreement or a Protocol Section sets forth a specific dispute resolution procedure, the provisions of this Section shall apply only if the dispute remains unresolved after the other specific dispute resolution procedures have been exhausted.

(3) Except in the case of a disagreement involving a variance that has been filed through the ERCOT retail transaction issue resolution system or other ERCOT data discrepancy tracking method (~~“~~i.e., the Data Extract Variance Process pursuant to the Retail Market Guide and Market-Trak Users Guide~~”~~), if the requested outcome of the ADR process involves the correction of ~~settlement~~ Settlement data and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, prior to requesting ADR, a Market Participant must comply with Section 9.~~5~~14, Settlement and Billing Dispute Process. If the Market Participant does not comply with Section 9.~~5~~14, then the Market Participant shall have waived the right to file a complaint regarding the Settlement Statement and ERCOT shall reject the ADR request without further action. Statement Recipients and Invoice Recipients are the only parties that may request the use of ADR where the requested relief would involve correction of ~~s~~Settlement data at ERCOT and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, except where the disagreement involves a variance that has been filed through the Data Extract Variance Process.

(4) This Section shall apply to disagreements involving variances that are filed through a Data Extract Variance Process. The filing party must have previously complied with all

requirements of a Data Extract Variance Process and submitted the initial variance by the deadline specified in the Data Extract Variance Process. A request for ADR relating to such a disagreement may seek the correction of the ~~settlement~~ Settlement data and resettlement by ERCOT pursuant to Section 9. A party requesting ADR in connection with a Data Extract Variance Process need not have filed a ~~settlement~~ Settlement and billing dispute pursuant to Section 9.~~5~~ 14 in order to request and, if appropriate, receive resettlement through the ADR process.

(5) The procedures in this Section do not apply to disputes for which the sole remedy requires a change to the Protocols or related Agreements. The forum for resolution of such disputes is the appropriate ~~change~~revision ~~or amendment~~ procedure(s) found in Section 21, Process for Protocol~~s~~ Revision.

(6) Nothing in this ADR ~~P~~procedure is intended to limit or restrict:

(~~1~~a) The rights of any party to file a complaint with the Public Utility Commission of Texas (PUCT) or any other Governmental Authority, with respect to matters other than those specified in this Section;

(~~2~~b) The right of ERCOT or any Market Participant to seek changes in rates or terms and conditions of services, or guidelines, criteria, Protocols, standards, policies, or procedures of ERCOT; or

(~~3~~c) The right of a Market Participant or ERCOT to file a petition seeking direct relief from the PUCT or any other Governmental Authority without first utilizing this ADR ~~P~~procedure where an action by ERCOT or a Market Participant might inhibit the ability of the affected party to provide continuous and adequate electric service.

(7) The arbitration procedures set forth in ~~subsection~~ Section 20.5, Arbitration Procedures, shall not apply to any claim that includes for punitive damages as a part of the requested relief. Such a claim may be pursued in the appropriate forum without pursuing the requirements for arbitration procedures contained in ~~Subsection~~ Section 20.5~~, Arbitration Procedures~~.

(8) Except for the provisions of~~ Section 20.1, Applicability~~this Section, the ADR ~~P~~procedure may be modified by mutual agreement of the parties.

(9) Parties shall exercise good faith efforts to timely resolve disputes under this Section.

(10) Nothing here is intended to supersede any dispute resolution process mandated by applicable law or regulation.

(11) Unless the parties to the dispute agree otherwise or unless an applicable tariff or law provides otherwise, the ADR ~~P~~procedure does not apply to disputes between two or more Market Participants who are either:

(~~1~~a) ~~parties~~ Parties to a bilateral agreement that relates to the subject matter of the dispute; or

(~~2~~b) ~~governed~~ Governed by tariffs that relate to the subject matter of the dispute.

20.2 Initiation and Pursuit of ADR Process

20.2.1 Requirement for Written Request

(1) In order to initiate the Alternative Dispute Resolution (ADR) ~~P~~procedure, a Market Participant must submit a written request for ADR to the General Counsel of ERCOT. ERCOT shall provide Notice to all parties to the dispute within seven ~~(7)~~ Business Days of receipt of the ADR request and shall include the ERCOT ADR number in the ~~n~~Notice. For ADR proceedings that involve more than one Market Participant ~~within five (5) Business Days of receipt of Notice from ERCOT~~, each Market Participant shall provide the name and contact information of a contact point ("Dispute Contact") within five Business Days of receipt of Notice from ERCOT. The written request shall include the following information:

(~~1~~a) The name of the disputing E~~e~~ntity;

(~~2~~b) ~~A~~ The name and contact information of Dispute Contact~~contact person~~ for the disputing E~~e~~ntity ~~and contact information for that person~~;

(~~3~~c) A description of the relief sought;

(~~4~~d) A detailed description of the grounds for the relief and the basis of each claim which must, at a minimum, identify which Protocol Section(s), any other approved market guide, or related Agreement(s) that the application, implementation, interpretation of or compliance with is being challenged; and

(~~5~~e) A list of all parties involved in the dispute.

(2) In addition to the foregoing requirements, for ADR proceedings involving ~~settlement~~ Settlement disputes submitted pursuant to Section 9.~~5~~14, Settlement and Billing Dispute Process, or for which the Market Participant seeks a monetary resolution, the Market Participant shall include the following additional information:

(~~1~~a) Operating Day(s) involved in the dispute;

(~~2~~b) Settlement dispute number; and,

(~~3~~c) Amount in dispute (*i.e.* the additional compensation requested by the Market Participant).

20.2.2 Deadline for Initiating ADR Procedure

(1) For any ADR ~~P~~procedure invoked in connection with a ~~settlement~~ Settlement and billing dispute submitted pursuant to Section 9.~~5~~14, Settlement and Billing Disputes, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1, Requirement for Written Request) within ~~forty-five (~~45 ~~)~~ days of the date that ERCOT denied the Market Participant's ~~settlement~~ Settlement and billing dispute. ERCOT shall post the dispute resolution date on the portion of the Market Information System (MIS) used for the processing of disputes.

(2) For any ADR ~~P~~procedure invoked in connection with a disagreement arising from a Data Extract Variance Process, the Market Participant submitting the ADR request must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1~~, Requirement for Written Request~~) no later than ~~forty-five (~~45 ~~)~~ days after issuance of the True-Up Statement for the applicable Operating Day.

(3) For any ADR ~~P~~procedure invoked in connection with any other matter that is not subject to this Section ~~20.2.2~~, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1~~, Requirement for Written Request~~) within six ~~(6)~~ months of the date on which information giving rise to the ADR request became available to the Market Participant.

20.2.3 Failure to Pursue ADR Procedure

If the Market Participant that requested the ADR fails to diligently pursue its claim, ERCOT shall send a Notification to the Market Participant's Dispute Contact setting forth a deadline within which the Market Participant must respond in order to preserve its rights. The deadline shall be no less than ~~fifteen (~~15~~)~~ days from the date ERCOT sends the Notification. If the Market Participant fails to timely respond to two ~~(2)~~ such Notifications by ERCOT, the Market Participant will be deemed to have waived its rights and the ADR shall be deemed closed. An affirmative statement in writing (including e-mail) that the Market Participant intends to pursue the ADR and a recommended course of action, including a proposed timeline, shall preserve the Market Participant's rights.

20.3 Informal Dispute Resolution

(1) Any dispute subject to Alternative Dispute Resolution (ADR) as described in this Section shall first be referred to a senior dispute representative of each of the parties to the dispute. The senior dispute representative shall be an individual with authority to resolve the dispute and administer the resolution (through delegation or otherwise). Such representatives shall make a good faith effort to resolve the dispute informally as promptly as practicable.

(2) If the senior dispute representatives cannot resolve the dispute by mutual agreement within ~~sixty (~~60~~)~~ days of the date on which they take part in a meeting, then the dispute shall be referred to either:

(~~1~~a) ~~mediation~~ Mediation on the request of any party pursuant to Section 20.4, Mediation Procedures; or

(~~2~~b) ~~arbitration~~ Arbitration on agreement of all parties pursuant to Section 20.5, Arbitration Procedures.

(3) When ERCOT is a party to the dispute and the parties waive the mediation and arbitration procedures by written agreement, the time periods for appeal of the ADR that are set forth in the applicable Public Utility Commission of Texas (PUCT) ~~regulations~~ Substantive Rules shall apply from the date of the meeting between the senior dispute representatives.

20.4 Mediation Procedures

(1) The parties shall agree on a mediator who has no past or present official, financial, or personal conflict of interest with respect to the issues or parties in dispute, unless the interest is fully disclosed in writing to all participants in the dispute and all such participants waive in writing any objection to the conflict of interest. If the parties are unable to agree on a mediator within ten ~~(10)~~ days of the request of any party to mediate, then the Commercial Mediation Rules of the American Arbitration Association (~~"~~"AAA~~"~~") will be used to select the mediator.

(2) The mediator and senior dispute representatives of the ~~disputing~~ parties ~~with authority to settle the dispute~~ shall commence mediation of the dispute within ~~fifteen (~~15~~)~~ days after the mediator's date of appointment. Communications regarding mediation shall be confidential and shall not be referred to or disclosed in any subsequent proceeding. The mediator shall aid the parties in reaching a mutually acceptable resolution of the dispute. The mediator shall have no authority to impose a resolution on the parties. If the parties have not resolved the dispute within ~~sixty (~~60~~)~~ days of the first meeting with the mediator, such parties shall be deemed to be at impasse and the dispute may be submitted to arbitration on agreement of all parties. If such agreement regarding submission to arbitration cannot be reached, any of the parties may apply for relief to the Public Utility Commission of Texas (PUCT), or any other Governmental Authority.

20.5 Arbitration Procedures

20.5.1 Initiation of Arbitration

(1) If all the parties have agreed to arbitrate as provided in this Section, any party to the dispute may initiate arbitration by serving a Notice of arbitration, by first class mail certified with return receipt requested, courier service or facsimile, on the other party or parties to the dispute. The Notice of arbitration shall include:

(~~1~~a) ~~a~~ A statement of claims~~,~~;

(~~2~~b) ~~a~~ A description of the relief sought~~,~~;

(~~3~~c) ~~a~~ A brief summary of grounds for relief and basis of each claim~~,~~;

(~~4~~d) ~~a~~ A list of all parties involved in the dispute~~,~~; and

(~~5~~e) ~~a~~ A description of the good faith efforts made to resolve the dispute under the informal dispute resolution procedures under this Section.

(2) Even if ERCOT is not a party to the dispute, a copy of the Notice of arbitration shall be served on the General Counsel of ERCOT. Arbitration proceedings shall be deemed to commence on the date on which the ~~n~~Notice of arbitration is received by the non-filing parties.

(3) Each non-filing party shall file a response to the statement of the claim, and shall submit any counterclaims, within ten ~~(10)~~ days of receiving the Notice of arbitration. The responses and any counterclaims shall be served on the General Counsel of ERCOT and all parties to the arbitration.

20.5.2 Selection of Arbitrators

(1) Within seven ~~(7)~~ days after the response to the statement of the claim is filed, the parties to the arbitration shall meet to discuss the selection of an arbitrator.

(2) Arbitration shall, if possible, be conducted before a single neutral arbitrator appointed by the parties. If the parties fail to agree on a single arbitrator within seven ~~(7)~~ days of their initial meeting, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. If there are more than two parties to the dispute, the parties filing the Notice of arbitration shall jointly select one arbitrator and the non-filing parties shall select another. The two arbitrators so chosen shall within seven ~~(7)~~ days select a third arbitrator to chair the arbitration panel. If the two arbitrators are unable to agree on a third arbitrator to chair the panel, the two arbitrators shall be dismissed, and the parties shall each appoint a replacement, and the two replacement arbitrators shall within seven ~~(7)~~ days select a third arbitrator to chair the panel.

(3) Arbitrators shall have no past or current official, financial, or personal conflict of interest with respect to the issues in dispute or parties, unless the interest is fully disclosed in writing to all participants and all participants waive in writing any objection to the conflict of interest.

(4) No party shall have any ex-parte communication with an arbitrator or proposed arbitrator subsequent to the time such person is proposed as an arbitrator and prior to completion of the arbitration process.

20.5.3 Intervention

(1) As soon as practicable after appointment of the arbitrator or the arbitration panel, the arbitrators shall submit to the General Counsel of ERCOT a summary of the dispute (which summary shall not include information claimed to be confidential, proprietary, or Customer-specific), which ERCOT shall post to the Market Information System (MIS). The summary by the arbitrators shall also specify a date for filing of interventions.

(2) An Entity seeking intervention must demonstrate that its rights or interests would be materially affected by the outcome of the arbitration and that it is subject to such outcome, and that it is subject to comparable facts and circumstances to those in dispute. Each party shall have an opportunity to respond to intervention requests. The arbitrators shall have full authority to grant, deny, or condition requests for intervention, including conferring party status on an Entity.

(3) Any Entity seeking to intervene in arbitration~~,~~ must agree to be bound by the ~~dispute resolution~~Alternative Dispute Resolution (ADR) ~~procedures P~~procedure of this ~~section~~ Section and by the decision of the arbitrators, or of any tribunal to which the decision is appealed, to the same extent as the parties to the arbitration. Intervenors shall share in the costs of the arbitration to the same extent as the other parties to the arbitration.

20.5.4 Conduct of Arbitration

Except as otherwise provided herein, the arbitrators have full discretion over the conduct of hearings, briefing, scheduling, discovery, and other procedural matters. The arbitrators shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the American Arbitrators Association (AAA) Commercial Arbitration Rules and any applicable rules and regulations of the PUCT or any other tribunal having jurisdiction. In the event of a conflict between the AAA Commercial Arbitration Rules and rules and regulations of the Public Utility Commission of Texas (PUCT) or any other Governmental Authority, the rules and regulations of the PUCT or any other Governmental Authority having appropriate jurisdiction shall control. In the event of a conflict between the AAA Commercial Arbitration Rules and this ADR ~~P~~procedure, the procedures set forth in this Section shall control. In addition:

(~~1~~a) The arbitrators shall allow reasonable opportunity for discovery.

(~~2~~b) In conducting hearings, the arbitrators shall apply the rules of evidence (including claims of privilege) to the same extent as such rules would be applied by the PUCT or any other Governmental Authority.

(~~3~~c) To the extent permitted by law, the arbitrators shall take appropriate actions to preserve the confidentiality of information claimed by a party to be confidential, proprietary or Customer-specific.

20.5.5 Arbitration Decisions

(1) The arbitrators shall be authorized only to interpret and apply the provisions of applicable statutory authority (including but not limited to the Public Utility Regulatory Act (PURA) or the Federal Power Act (FPA)), applicable rules, regulations and policies of regulatory authorities having jurisdiction (the PUCT or any other Governmental Authority), and these Protocols and related Agreements, and shall have no power to modify or change any of the foregoing.

(2) Within ~~one hundred and twenty (~~120~~)~~ days of appointment, the arbitrators shall render a final decision resolving the dispute. Such decision shall be based on the evidence in the record, the terms of the relevant Agreements and these Protocols, applicable statutes (including but not limited to PURA or the FPA), and applicable rules, regulations, and policies of the regulatory authority having jurisdiction (the PUCT or any other Governmental Authority). Such decision shall be in writing and shall provide the reasons therefore. The arbitrators may agree with the positions of one or more parties or may adopt a different resolution. The arbitrator shall not have authority to grant punitive damages. If the decision is not rendered within ~~one hundred and twenty (~~120~~)~~ days of appointment, the arbitrators shall forfeit their fee and any of the parties may apply for relief to the PUCT or any other Governmental Authority having jurisdiction or to any court of competent jurisdiction.

(3) If the decision of the arbitrators is not timely appealed as provided in Section 20.5.6, Appeal of Arbitration Decision, the decision shall be final and binding on the parties. The parties shall take whatever action is required to comply with the decision, and judgment on the decision may be entered and enforced in any court having jurisdiction. Unless appealed, the final decision is binding precedent on the parties and intervenors with respect to the subject matter of the dispute, but is otherwise of no precedential force or effect.

20.5.6 Appeal of Arbitration Decision

(1) Any party to an arbitration under this Section may appeal an arbitration decision to the applicable authority (the PUCT or any Governmental Authority) by providing written notice to that effect to all other parties and intervenors in the arbitration, the arbitrators, ERCOT (if not otherwise served), and the applicable regulatory authority, no later than ~~thirty (~~30~~)~~ days following the date the arbitration decision is issued.

(2) A party to arbitration under this Section may appeal the decision of the arbitrators only on the following grounds:

(~~1~~a) An arbitrator failed to disclose a conflict of interest with one or more of the parties to the dispute, and the decision is substantially biased as a result of the undisclosed conflict;

(~~2~~b) The decision is inconsistent with, or beyond the scope of, the relevant Agreements or these Protocols; or

(~~3~~c) The decision is unjust, unreasonable, unduly discriminatory or preferential, or otherwise inconsistent with applicable statutes or with applicable rules, regulations and policies of the authority having jurisdiction (the PUCT or any other Governmental Authority).

(3) Any appeal of an arbitration decision shall be based solely on the record assembled by the arbitrators, unless all parties to the dispute agree in writing to reopen the record for a specified purpose. ERCOT and Market Participants intend that in any appeal, the applicable regulatory authority should accord substantial deference to the factual findings of the arbitrators.

(4) During the pendency of an appeal, the effect of the arbitration decision shall be stayed, unless the disputing parties otherwise agree.

(5) Agreement to these appellate review procedures shall be a precondition for intervention by an Entity other than ERCOT or a Market Participant in an arbitration proceeding under this Section.

20.6 Dispute Resolution Costs

(1) Each party shall be responsible for its own costs incurred during ~~this~~ an Alternative Dispute Resolution (ADR) ~~P~~procedure and for a pro rata share of the cost of the mediator or arbitrators. The pro rata share will be based on the number of parties.

(2) The arbitrators may impose costs against an offending party if the arbitrators conclude that the party has abused ~~this~~ the ADR ~~P~~procedure.

20.7 Requests for Data

(1) If, as part of the Alternative Dispute Resolution (ADR) ~~P~~procedure, a party requests documents or data from another party to the ADR, the responding party must provide within 15 days of the request either:

(~~1~~a) ~~the~~ The requested documents or data ~~to the requesting party within fifteen (15) days of the request~~;

(~~2~~b) ~~an~~ An explanation of why the party believes the documents or data should not be produced (*e.g.* relevance); or,

(~~3~~c) ~~an~~ An explanation of why the information cannot be provided on that date and a reasonable date on which the documents or data will be produced.

(2) Additionally, if the ADR proceeds to mediation or arbitration, a party may request that arbitrator or mediator decide if documents or data are relevant to the ADR and, if it is relevant to the ADR, the document or data must be provided by the other party within a timeframe specified by the mediator or arbitrator.

(3) ERCOT and Market Participants will protect from public disclosure any and all Protected Information provided in response to the ADR ~~P~~procedure pursuant to a mutually agreeable confidentiality agreement.

(4) All information provided pursuant to this subsection may be provided by mail, facsimile, or other electronic communications.

20.8 Resolution of Disputes and Notification to Market Participants

(1) Upon resolution of an Alternative Dispute Resolution (ADR) claim, ERCOT and/or the Market Participants must enter into a written dispute resolution agreement disposing of the Market Participant's claim.

(2) ERCOT shall send a Notification of the negotiated settlement amount and the manner in which the resulting overpayments or underpayments will be allocated to the appropriate Settlement Statement and Invoice Recipients, including the specific Settlement Statements and ~~Settlement~~ Invoices that will be affected. The Notification shall provide details including, but not limited to, the Operating Day, service type, total amount of the adjustment to the market and total adjustment to the Invoice Recipient.

(3) In the event a determination is made that there has been an error in ERCOT's processes, procedures, or systems that resulted in overpayments or underpayments to one or more Market Participants, the Chief Executive Officer (CEO) of ERCOT may negotiate a resolution to a dispute arising from such error in a manner that deviates from the normal application of the Protocols in order to settle the dispute under this ADR ~~P~~procedure with the approval of the ERCOT Board ~~of Directors~~. These occurrences will be subject to the requirements of Section 9.2.6, Notice of Resettlement for the DAM, or Section 9.5.7, Notice of Resettlement for the Real-Time Market.~~9.2.5.1, Notice of Resettlement.~~

20.9 Settlement of Approved Alternative Dispute Resolution~~ADR~~ Claims

20.9.1 Adjustments Based on Alternative Dispute Resolution~~ADR~~ Resolution

(1) If Resettlement is possible to address an adjustment required by an Alternative Dispute Resolution (ADR) resolution, ERCOT shall issue a Resettlement Statement for the affected Operating Day(s) and shall adjust applicable timelines accordingly.

(2) If a resettlement is not practical or possible to address an adjustment required by an ADR resolution, ERCOT shall make the adjustments through a separate "ADR Invoice" that is produced outside of the normal ~~settlement~~ Settlement system. The appropriate payments and charges, along with settlement quality information, shall be supplied to all Market Participants. Any dispute resolution amount greater than ~~five million dollars (~~$5,000,000~~)~~ shall be divided so that no one ADR Invoice has more than ~~five million dollars (~~$5,000,000~~)~~ in ADR adjustments and such ADR Invoices shall be issued at least ~~fourteen (~~14~~)~~ days apart from each other. Payments will be due on the date specified on

the ADR Invoice. Any short and late payments will be handled pursuant to Section 9.4.4, Partial Payments and 9.4.6, Late Fees respectively.

20.9.2 Charges for Approved ADR Claim

The charges assigned to Market Participants to pay for an approved ADR claim will be settled on the same Settlement Statement as set forth in Section 20.9.1, Adjustments Based on ADR Resolutions. ERCOT will assign the costs for the approved ADR claim according to the appropriate allocation for the market service in dispute as outlined in Section 6.9, Settlement for ERCOT-Provided Ancillary Services; Section 7.4, Congestion Management for Local Congestion; and, other Protocol Sections as appropriate. Charges that are necessary relating to other types of dispute resolution will be made in pursuant to the directives of the Protocols.

Protocol Revision Request

NPRR Number	112	NPRR Title	Emergency Base Point Price Revision
Date Posted		March 5, 2008	

Protocol Section(s) Requiring Revision (Include Section No. and Title)	6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal.
Revision Description	This Nodal Protocol Revision Request (NPRR) clarifies the calculation of the *Emergency Base Point Price per QSE per Resource by interval (EBPPR)* variable.
Reason for Revision	This NPRR is being proposed in order to: 1) Establish a methodology to extend the Energy Offer Curve to allow determination of Emergency Base Point Price. 2) Redefine methodology to calculate the Emergency Base Point Price, as requested by the Transition Plan Task Force (TPTF).
Overall Market Benefit	The proposal establishes consistency in Energy Offer Curve extension methodology between the Market Management System (MMS) and Settlements. It also reduces the *Charge for Emergency Power Increases (LAEMREAMT).*
Overall Market Impact	None.
Consumer Impact	None.
Credit Implications (Yes or No, and summary of impact)	None anticipated.
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☒(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☐(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	On 2/21/08, TPTF voted to endorse forwarding to PRS for consideration the draft NPRR for Emergency Base Point Price Revision as submitted to TPTF on February 21, 2008. There were nine abstentions from the Consumer (7) and Independent Power Marketer (2) Market Segments.

Protocol Revision Request

Quantitative Impacts and Benefits

Assumptions	1	*Formulas should accurately the intent of the Protocols and accuracy enhances transparency of the market.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1		
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1		
	2		
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Protocol Revision Request

Proposed Protocol Language Revision

6.6.9.1 Payment for Emergency Power Increase Directed by ERCOT

(1) If the Emergency Base Point issued to a Generation Resource is higher than the SCED Base Point immediately before the Emergency Condition, then ERCOT shall pay the QSE an additional compensation for the Resource at its Resource Node Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{EMREAMT}_{\boldsymbol{q, r, p}} = \mathbf{(-1) * EMREPR}_{\boldsymbol{q, r, p}} \mathbf{* EMRE}_{\boldsymbol{q, r, p}}$$

Where:

$$\text{EMREPR}_{q, r, p} = \text{Max}\,(0, \text{EBPWAPR}_{q, r, p} - \text{RTSPP}_{p})$$

$$\text{EBPWAPR}_{q, r, p} = \sum_{y} (\text{EBPPR}_{q, r, p, y} * \text{EBP}_{q, r, p, y} * \text{TLMP}_{y}) \,/\, \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y})$$

$$\text{EMRE}_{q, r, p} = \text{Max}\,(0, \text{Min}\,(\text{AEBP}_{q, r, p} * ¼\ \text{RTMG}_{q,r, pr}) - ¼ * \text{BP}_{q, r, p})$$

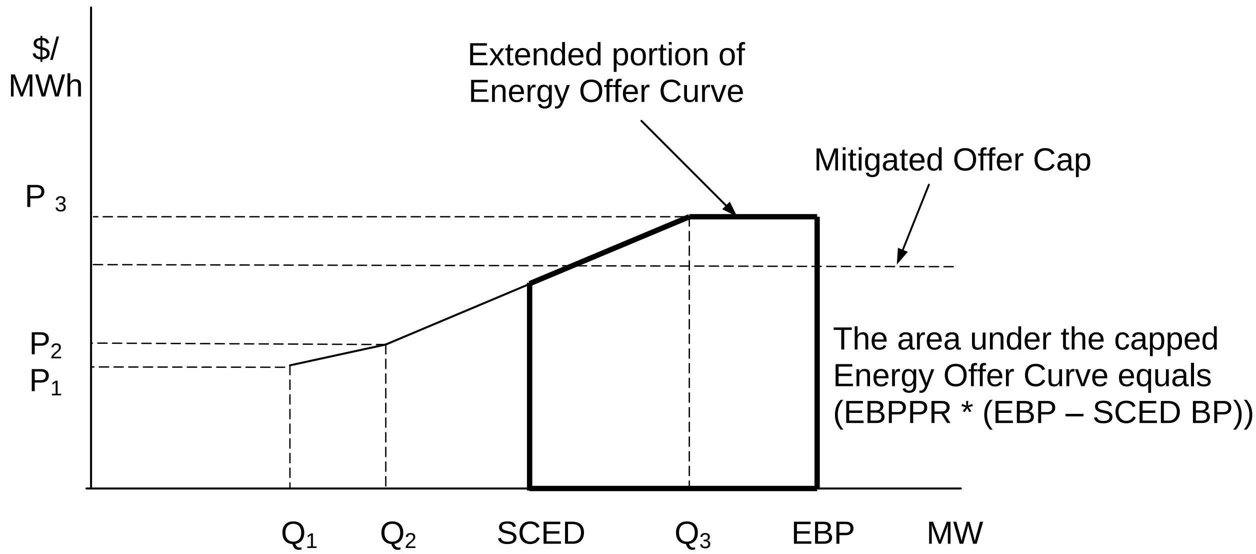
$$\text{AEBP}_{q, r, p} = \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y} / 3600)$$

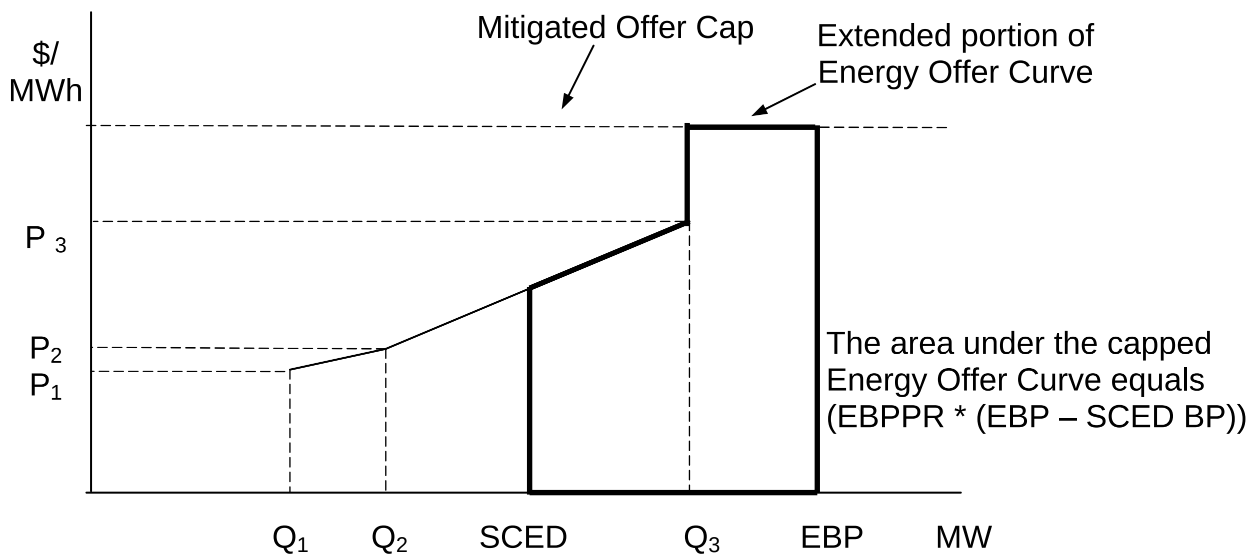
The above variables are defined as follows:

Variable	**Unit**	**Definition**
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EMREPR $_{q, r, p}$	$/MWh	*Emergency Energy Price per QSE per Settlement Point per Resource*—The compensation rate for the additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EMRE $_{q, r, p}$	MWh	*Emergency Energy per QSE per Settlement Point per Resource*—The additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EBPWAPR $_{q, r, p}$	$/MWh	*Emergency Base Point Weighted Average Price per QSE per Settlement Point per Resource*—The weighted average of the energy prices corresponding with the Emergency Base Points on the Energy Offer Curve for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval.

$BP_{q, r, p}$	MW	*Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition.
$AEBP_{q, r, p}$	MW	*Aggregated Emergency Base Point*— The Generation Resource's aggregated Emergency Base Point, for the 15-minute Settlement Interval.
$EBP_{q, r, p, y}$	MW	*Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point.
$EBPPR_{q, r, p, y}$	$/MWh	*Emergency Base Point Price per QSE per Settlement Point per Resource by interval* – The average incremental energy cost calculated per the Energy Offer Curve for the output levels between the SCED Base Point immediately before the Emergency Condition and the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*~~*Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The Real-Time energy offer price corresponding with the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q*, for the Emergency Base Point interval or SCED interval *y*.~~
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTMG_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval.
$TLMP_{y}$	second	*Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.

(2) The extension of the Energy Offer Curve used to calculate the Emergency Base Point Price is illustrated with the pictures below. If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve submitted by the QSE for the Resource, then the Energy Offer Curve is extended to the Emergency Base Point MW value with a $/MWh value that is the greater of the highest $/MWh value on the Energy Offer Curve submitted by the QSE or the Mitigated Offer Cap (pursuant to Section 4.4.9.4.1, Mitigated Offer Cap) for the highest MW output on the Energy Offer Curve submitted by the QSE for the Resource.





(~~2~~3) The total additional compensation to each QSE for emergency power increases of Generation Resources for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{EMREAMTQSETOT}_{q} = \sum_{r} \sum_{p} \textbf{EMREAMT}_{q, r, p}$$

The above variables are defined as follows:

Variable	Unit	Definition

$EMREAMTQSETOT_{q}$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for emergency power increases of the non-RMR Generation Resources represented by this QSE for the 15-minute Settlement Interval.
$EMREAMT_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
q	None	A QSE.
p	None	A Resource Node Settlement Point.
r	None	A Generation Resource.

Protocol Revision Request

NPRR Number	113	NPRR Title	Load Resource Type Indicator for Ancillary Service (AS) Trades and Self-Arranged AS
Date Posted		March 11, 2008	

Protocol Section(s) Requiring Revision (Include Section No. and Title)	4.4.7.1, Self-Arranged Ancillary Service Quantities 4.4.7.3.1, Ancillary Service Trade Criteria
Requested Resolution (Normal or Urgent, and justification for Urgent status)	Normal
Revision Description	This Nodal Protocol Revision Request (NPRR) adds an indicator to Self-Arranged Ancillary Services (AS) and AS Trades to reflect if Responsive Reserve Services (RRS) are being provided from a Generation Resource, Controllable Load Resource, or non-controllable Load Resource.
Reason for Revision	ERCOT should not allow or procure more than 50% of RRS from non-controllable Load Resources. This NPRR prevents this from occurring by specifying the data in the Self-Arranged AS and AS Trades submitted by Qualified Scheduling Entities (QSEs).
Overall Market Benefit	This NPRR increases the transparency of which RRS type is being self-arranged and traded.
Overall Market Impact	This NPRR may impact the QSE business functions and systems for submission of Self-Arranged AS and AS Trades.
Consumer Impact	None
Credit Implications (Yes or No, and summary of impact)	None anticipated.
Reason for Revision (from Transition Plan Task Force (TPTF) Charter Scope)	☐(1) Revisions resulting from Commission orders; ☐(2) Clarifications of Protocol language that do not change the intent or technical specifications of the Protocols; ☒(3) Correction of technical errors or processes that are found to not be technically feasible; ☐(4) Revisions to the Protocols necessary to implement the results of the value engineering analysis or to otherwise avoid severe cost impacts; or ☐(5) Other (describe):
TPTF Review (Yes or No, and summary of conclusion)	TPTF review to occur March 20, 2008

Protocol Revision Request

Quantitative Impacts and Benefits

Assumptions	1	*Changes needed to ERCOT and QSE systems to properly track provisioning of Ancillary Services in maintaining 50% limit of RRS from non-controllable Load Resources.*	
	2		
	3		
	4		
Market Cost		**Impact Area**	**Monetary Impact**
	1	*Unknown*	*Unknown*
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1		
	2		
	3		
	4		
Additional Qualitative Information	1		
	2		
	3		
	4		
Other Comments	1		
	2		
	3		
	4		

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Proposed Protocol Language Revision

4.4.7.1 Self-Arranged Ancillary Service Quantities

(1) A QSE may self-arrange all or a portion thereof, but not to exceed, the Ancillary Service Obligation allocated to it by ERCOT. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation.

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a Supplemental Ancillary Service Market.

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources or Load Resources, or backed by Ancillary Service Trades.

(5) When a QSE chooses to self-arrange all or a portion of its Ancillary Service Obligations, it commits to the following conditions:

(a) The QSE may self-arrange Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve Service (RRS), and Non-Spin;

(b) The QSE may provide all or part of its Self-Arranged Ancillary Service Quantity from one or more Resources it represents;

(c) The QSE may provide all or a part of its Self-Arranged Ancillary Service Quantity through an Ancillary Service Trade;

(d) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a Supplemental Ancillary Service Market notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT;~~ and~~

(e) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of the Ancillary Service Obligation for the QSE; and~~.~~

(f) For self-arranged Responsive Reserve Service, the QSE shall indicate the quantity of the service that is provided from Generation Resources, Controllable (CLR) Load Resources or non-CLR Load Resources.

4.4.7.3.1 Ancillary Service Trade Criteria

(1) Each Ancillary Service Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The type of Ancillary Service;

(d) The quantity in MW; ~~and~~

(e) The first and last hours of the trade; and

(f) For Responsive Reserve Service, the QSE shall indicate the quantity of the service that is provided from Generation Resources, Controllable (CLR) Load Resources or non-CLR Load Resources.

(2) An Ancillary Service Trade must be confirmed by both the buying QSE~~er~~ and selling QSE~~er~~ to be considered valid and to be used in an ERCOT process.