Public Utility Commission of Texas

# 2002 Annual Report on The ERCOT Wholesale Market

**Project No. 26390, *MOD Report on the ERCOT Wholesale Market – The First Year***


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# Acknowledgement

Collection of data and information and the preparation of annual reports have been important functions for market monitors in the wholesale electricity markets in the United States and abroad. Annual reports provide valuable information to market participants and the public to improve market transparency and facilitate the assessment of the competitiveness of electricity markets. The single control area operation of the competitive wholesale electricity market in the Electric Reliability Council of Texas (ERCOT) began on July 31, 2001. However, this is the first annual report prepared by the Market Oversight Division (MOD) of the Public Utility Commission of Texas. The report actually covers the first 17 months of wholesale market activities in the ERCOT from July 31, 2001 to December 31, 2002.

Since its creation in September 2000, MOD has been actively involved in ERCOT Protocol issues, market design issues, and market monitoring activities. This report provides an overall review of market performance in the first 17 months and a summary of the key issues and activities with which MOD has been involved. Many of the issues that MOD addressed were related to ensuring compliance with the Commission's rules and orders established in various rulemaking proceedings and docketed cases.

While the first 17 months of experience in the ERCOT Wholesale Market demonstrated that the market was working relatively well, the Market Oversight Division still feels that it is important to monitor market operations and continue to improve market design and operating rules in order to ensure a successful and workably competitive electricity market in Texas. The Market Oversight Division Staff has prepared this report to provide more market transparency and facilitate critical evaluation of ERCOT wholesale electricity market competitiveness.

I would like to take this opportunity to show appreciation for months of hard work by team members Julie Gauldin, Richard Greffe, Dr. David Hurlbut, Danielle Jaussaud, and Dr. Sam Zhou. Special thanks go to Richard Greffe, Project Team Leader, who also put the whole report together and provided excellent help in editing this report.

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## Table of Contents

## List of Tables

## List of Figures

# EXECUTIVE SUMMARY

This is the first annual report prepared by the Market Oversight Division (MOD) of the Public Utility Commission of Texas (PUC or Commission). It actually covers the first 17 months of wholesale market activities in the Electric Reliability Council of Texas (ERCOT) from July 31, 2001 to December 31, 2002. Since its creation in September 2000, MOD has been actively involved in ERCOT Protocol issues, market design issues, and market monitoring activities. This report provides an overall review of market performance in the first 17 months and a summary of the key issues and activities with which MOD has been involved. Many of the issues that MOD addressed were related to ensuring compliance with the Commission's Order on Rehearing in Docket No. 23220[1] and addressing the additional issues that were covered in Docket No. 24770.[2]

## Ancillary Service Markets

The majority of load in the ERCOT region is served through bilateral transactions or generation with native load, but ERCOT deploys ancillary services in order to maintain the security and reliability of the transmission system. These services include five capacity ancillary services which are acquired in the Day-ahead market (Regulation Up, Regulation Down, Responsive Reserve, Non-Spinning Reserve, and Replacement Reserve) and two balancing energy services (Down Balancing and Up Balancing) which are acquired during the Operating Period approximately 20 minutes before the time of actual power flow.

**ERCOT Market Timeline**

| 6:00 AM – 6:00 PM | | 1 Hour | |
|---|---|---|---|
| **Day Ahead Market** | **Adjustment Period** | **No Adjustments** | **Operating Hour** |
| | | **Operating Period** | |

### Capacity Ancillary Services

ERCOT assigns responsibility for providing the capacity services (excluding Replacement Reserve) to Qualified Scheduling Entities[3] (QSEs) on the basis of their historical load ratio shares. A QSE can self-arrange its ancillary service obligations or designate ERCOT to procure ancillary services on its behalf in the Day-ahead market. In the first 17 months of the market, QSEs relied primarily on self-arrangement of ancillary services; however, there was a gradual increase in the level of these services procured by ERCOT. The trend from September 2001 to December 2002 toward greater procurement of ancillary services by ERCOT (3.2% vs. 20%)

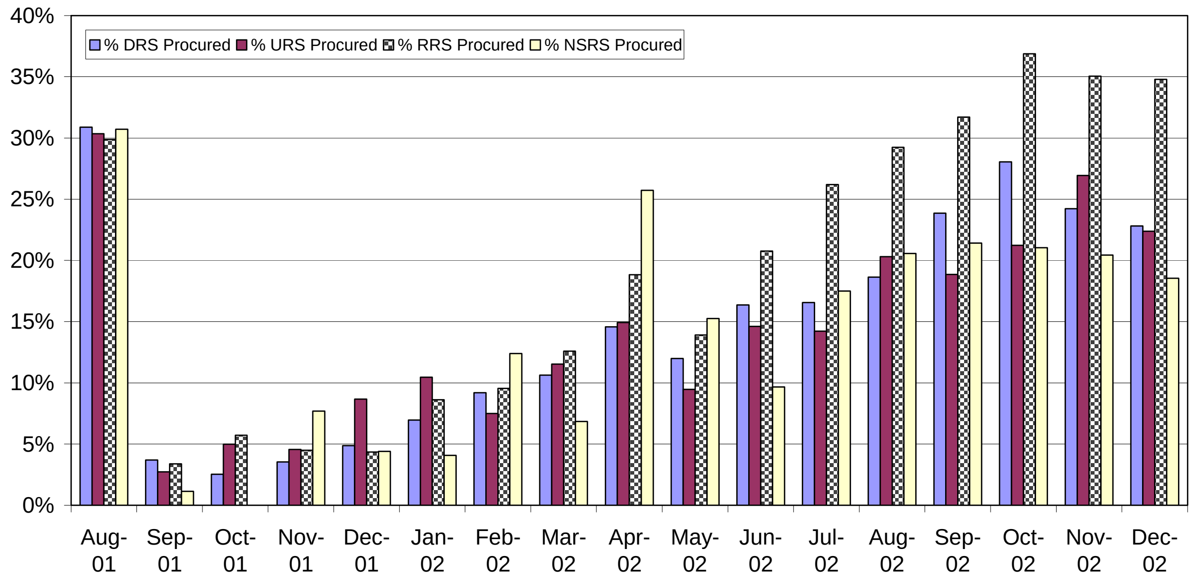
[1] *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, Docket No. 23220, Order on Rehearing, June 4, 2001.

[2] *Report of the Electric Reliability Council of Texas Regarding Certain Market Design Issue*, Docket No. 24770 (pending).

[3] Resources (and load serving entities) must be represented by QSEs in scheduling and settlement with ERCOT.

implies that QSEs became more willing to rely on the market to provide these services at a cost that was equal to or less than the cost of providing the services from their own resources or acquiring them bilaterally.

**Percent of Ancillary Services Procured by ERCOT**




The overall price for ancillary services procured by ERCOT in 2002 was $8.23/MW. Average prices for individual services ranged from a low of $6.07/MW for Regulation Down to a high of $35.18/MW for Non-spinning Reserve. The price for Non-Spinning Reserve was affected by several price spikes, especially on April 30th when ERCOT procured the service for 12 hours and the Market Clearing Price for Capacity (MCPC) in each hour was $990-$999/MWh. The total cost for Non-Spinning Reserve on that day was $7.9 million.

**Weighted Average Prices for Ancillary Services ($/MW)**

| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve | Total |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | $10.80 | $9.97 | $10.59 | $12.40 | $10.59 |
| **2002** | $7.38 | $6.07 | $7.76 | $35.18 | $8.23 |

In comparison to New York and California, ERCOT regulation prices tended to be lower, but the spinning and non-spinning reserve prices tended to be higher. In 2002 the ancillary service prices in California were $13.41/MW for regulation up, $13.76/MW for regulation down, $4.66/MW for spinning reserve, and $2.15/MW for non-spinning reserve.[4] The California prices include both day-ahead and hour-ahead markets so they are not exactly comparable to the

[4] "2002 Annual Report on Market Issues and Performance," California Independent System Operator, April 2003, p. 5-10.

ERCOT Day-ahead market prices. In New York, the monthly average price for regulation in the day-ahead market ranged from about $12/MW to $24/MW.[5] New York has three categories of operating reserves, and all but one of the monthly average prices in 2002 were less than $5/MW.

ERCOT ancillary services frequently exhibited price reversals in 2001 and 2002. A price reversal occurs when the MCPC for a less valuable service such as Responsive Reserve is higher than the MCPC for a more valuable service such as Regulation Up. Price reversals can occur when the same capacity is bid for more than one service and the market clearing prices are determined sequentially. To address this issue, the Commission's ordered simultaneous selection of ancillary services in Docket No. 23220. In January 2003, the ERCOT Board of Directors approved Protocol Revision Request (PRR) 342 which will implement simultaneous selection for Regulation Up, Regulation Down, and Non-Spinning Reserves.

The total cost for ancillary services procured in 2002 was $77.6 million in 2002. Seventy-five percent of the cost in 2001 was incurred in August when ERCOT procured more than 30% of its ancillary service requirements from the market.

**Total Cost of Ancillary Services[6]**

| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve | Total |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | $6,852,987 | $6,141,615 | $8,744,232 | $1,687,244 | $23,426,077 |
| **2002** | $12,504,806 | $16,335,654 | $36,439,136 | $12,317,824 | $77,597,420 |

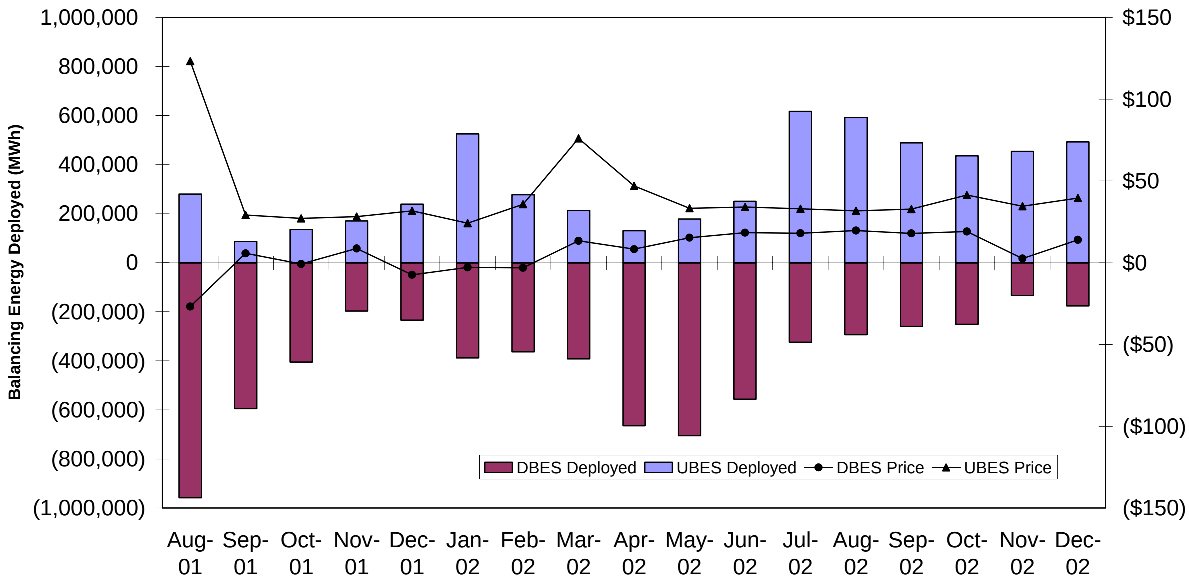
### Balancing Energy Service

QSEs must bid 15% of their scheduled generation as Down Balancing energy, but there are no specific obligations for Up Balancing bids. Balancing energy bids are submitted by zone, and they include a ramp rate. The bid stack is fixed for the Operating Hour, but balancing energy is deployed in 15-minute intervals. The market clears 20 minutes prior to the operating interval, based on projections obtained using short-term forecasting tools. In 2001 and 2002, balancing energy bids were capped at $1000/MWh.

Balancing energy accounts for only a small percentage of the total energy in ERCOT. In 2002, Down Balancing was 1.6% of ERCOT energy and Up Balancing was 1.7%. The relative amounts of Down Balancing versus Up Balancing energy deployed changed significantly from month to month during the first 17 months of the market. When the Relaxed Balanced Schedule was implemented in November 2002, it was anticipated that balancing energy deployments could be affected since schedules had to accurately represent generation but not necessarily load. However, there was no significant change in balancing energy deployments in the last two months of 2002.

5 "2002 State of the Market Report – New York ISO," Potomac Economics, Ltd., Independent Advisor to the New York ISO, June 2003, p 3.
6 Costs are based on ERCOT Day Ahead Reports and may not correspond directly to financial settlements.

**Deployments and Weighted Average Prices for Balancing Energy**




In 2002, the ERCOT average prices for balancing energy were sometimes lower and sometimes higher than California and New York. In California the average price for incremental energy (INC) was $53.04/MWh versus $36.03/MWh in ERCOT, but the average price for decremental energy (DEC) was $8.79 versus $11.86/MWh in ERCOT.[7] In New York, imbalance energy is paid at the Real-Time Locational-based Marginal Price (RT-LBMP) and the price is determined by zone. In 2002 the RT-LBMP was $48.55/MWh in New York City, $38.99/MWh in the Capital Zone, and $31.37 in the West Zone.[8]

Since ERCOT generation is now more than 70% gas-fired, ERCOT energy prices are significantly impacted by changes in the price of natural gas. In 2002, natural gas prices at the Houston Ship Channel doubled from about $2.25/MMBTU in January to about $4.50/MMBTU in December. At the same time, Up Balancing prices went from about $24/MWh in January to about $39.50/MWh in December.

The total cost for balancing energy was $75.7 million in 2001 and $114.2 million in 2002. More than $60 million in balancing energy costs were incurred during the month of August 2001 due to the high levels of zonal congestion that occurred (see Sections III.B, III.D, and IV.A).

[7] "2002 Annual Report on Market Issues and Performance," California Independent System Operator, April 2003, p. 4-3.

[8] "2002 State of the Market Report – New York ISO," Potomac Economics, Ltd., Independent Advisor to the New York ISO, June 2003, p 6.

**Total Cost for Balancing Energy**[9]

| Month | Down Balancing | Up Balancing | Total Cost |
|---|---|---|---|
| **2001 (Aug-Dec)** | ($22,557,555) | $53,162,699 | $75,720,254 |
| **2002** | $53,421,393 | $167,649,329 | $114,227,936 |

## Congestion, TCRS, and the TCR Auction Market

### Congestion Management Method

ERCOT uses a zonal, portfolio-based model which classifies the region into zones and identifies the commercially significant interfaces between the zones as Commercially Significant Constraints (CSCs). In 2001 there were three zones and two CSCs (South-North and West-North); and in 2002 there were four zones and four CSCs (South-North, South-Houston, West-North, North-West).

ERCOT solves zonal and local congestion in two steps, in conjunction with a security-constrained dispatch. In the first step, ERCOT dispatches zonal balancing energy to clear congestion on the CSCs, sets the shadow price for each CSC, and it determines the market clearing price for each congestion zone. If there is no zonal congestion, the MCPE is the same for the entire ERCOT region. In the second step, ERCOT uses resource specific premiums to clear local constraints and to issue resource specific instructions to relieve local congestion, and it uses additional resource specific instructions to rebalance the zonal energy. Generators submit resource specific premiums that specify the additional payments that they require for the deployment of incremental or decremental balancing energy from the associated, specific resource, if a Market Solution[10] exists. However, more than 90 percent of the time in 2001 and 2002 a Market Solution did not exist. When a Market Solution does not exist, ERCOT issues out-of-merit (OOM) dispatch instructions.

### Zonal Congestion Costs

Zonal congestion charges during the first 17 months of the market were $187.66[11] million, but the month of August 2001 accounted for 73% ($136.74 million) of the total. Payments for load imbalances that occurred in August resulted in very high charges for the Balancing Energy Neutrality Adjustment (BENA), which were uplifted to all market participants. On February 15, 2002, market rules were changed to require the direct assignment of zonal congestion costs, and Transmission Congestion Rights (TCRs) were introduced to allow market participants to hedge their zonal congestion charges. Zonal congestion charges from July 31, 2001 to February 15, 2002 were $165 million, but from February 15 to the end of December 2002 the charges were

[9] Costs are based on ERCOT Operating Day Reports and may not correspond directly to financial settlements. Consistent with those reports, a negative value for Down Balancing in represents net payments from ERCOT to QSEs and a positive value for Down Balancing represents net payments from QSEs to ERCOT. Therefore, the Total Cost equals Up Balancing Cost minus Down Balancing Cost.

[10] A Market Solution exists when at least three unaffiliated resources, with capacity available, submit bids to ERCOT that can solve a circumstance of local congestion and no one bidder is essential to solving the congestion.

[11] Zonal congestion costs based on generation schedule and load schedule.

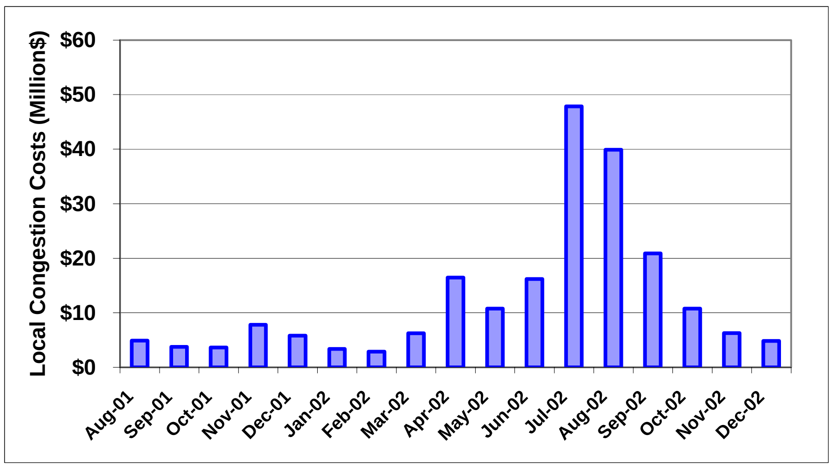
only $22.6 million since direct assignment eliminated the financial incentives for QSEs to overschedule.

## Local Congestion Costs

Local congestion costs were about $212 million during the first seventeen months of the market, including $25.9 million in 2001 and $186.3 million in 2002. The OOME Down costs were, and continue to be, socialized, making it possible for market participants that own generation on the constrained side of a local constraint to game the market by using the "DEC" game. The DEC game occurs when (1) a market participant submits a schedule that if followed would cause congestion; (2) the market participant is paid to "solve" the anticipated congestion by generating less than what was scheduled; and (3) the cost of these local congestion payments are socialized.

**Local Congestion Costs**

| Month | Local Congestion Costs (Million$) |
|---|---|
| Aug-01 | $4.89 |
| Sep-01 | $3.77 |
| Oct-01 | $3.63 |
| Nov-01 | $7.78 |
| Dec-01 | $5.81 |
| Jan-02 | $3.36 |
| Feb-02 | $2.86 |
| Mar-02 | $6.26 |
| Apr-02 | $16.43 |
| May-02 | $10.76 |
| Jun-02 | $16.17 |
| Jul-02 | $47.85 |
| Aug-02 | $39.90 |
| Sep-02 | $20.86 |
| Oct-02 | $10.74 |
| Nov-02 | $6.27 |
| Dec-02 | $4.84 |
| Total | $212.19 |




Local congestion consistently occurs in several specific locations, but with different patterns in 2001 and 2002. For example, in 2001 the DFW Area was the eighth highest local congestion cost area and accounted for only 3.5% of the costs, but in 2002 it was ranked number one and accounted for 27.6% of the costs. The Wind Area, which is an area of concentrated wind generation near McCamey, Texas, also experienced a significant increase in local congestion in 2002. Currently, market participants are discussing a plan that would reduce the congestion uplift generated by the wind resources by eliminating almost all OOME Down payments and issuing tradable physical transmission rights on a resource share basis behind the constraint.

## ERCOT Uplift

Uplift charges were $118.8 million in 2001 and $277.2 million in 2002 including ERCOT Administrative Fees of $25.4 million and $61.5 million, respectively. The 2001 uplift charges include the high level of BENA charges that were incurred in August 2001. Uplift costs increased significantly in the last half of 2002, especially charges for Local Balancing Energy Service Charge (Category 4), OOME, OOM Capacity (OOMC), and Reliability-Must-Run (RMR).

## ERCOT Administration Fee and Uplift Costs

| Month | ERCOT ADMIN FEE | BALANCING ENRGY NEUTRALITY ADJUSTMENT | BLACK START CAPACITY CHARGE | LOCAL BALANCING ENERGY SERVICE CHARGE | OOM ENERGY CHARGE | OOM REPLACEMENT CAPACITY CHARGE | REPLACEMENT RESERVE UPLIFT CHARGE | RMR RESERVE SERVICE CHARGE | Total |
|---|---|---|---|---|---|---|---|---|---|
| Jul-01 | $ 229,205 | $ (146,046) | - | - | $ 398,983 | - | - | - | $ 482,142 |
| Aug-01 | $ 6,566,363 | $ 63,293,414 | - | - | $ 4,407,605 | $ 86,591 | $ 7,206 | - | $ 74,361,179 |
| Sep-01 | $ 5,278,208 | $ 256,392 | - | - | $ 2,051,896 | $ 1,802,389 | - | - | $ 9,388,884 |
| Oct-01 | $ 4,526,921 | $ 2,630,931 | - | - | $ 2,313,647 | $ 1,485,032 | - | - | $ 10,956,531 |
| Nov-01 | $ 4,262,083 | $ 160,880 | - | - | $ 6,247,669 | $ 2,003,850 | - | - | $ 12,674,482 |
| Dec-01 | $ 4,528,600 | $ 624,938 | - | - | $ 3,096,790 | $ 2,710,868 | - | - | $ 10,961,195 |
| Jan-02 | $ 4,714,204 | $ 4,490,799 | $ 616,828 | - | $ 2,019,361 | $ 1,345,463 | - | - | $ 13,186,655 |
| Feb-02 | $ 4,248,696 | $ 8,098,418 | $ 557,135 | - | $ 2,025,143 | $ 836,514 | - | - | $ 15,765,906 |
| Mar-02 | $ 4,490,335 | $ (387,765) | $ 616,829 | - | $ 4,045,236 | $ 2,245,948 | - | - | $ 11,010,582 |
| Apr-02 | $ 4,681,842 | $ 6,352,883 | $ 596,101 | - | $ 13,870,571 | $ 2,722,634 | - | - | $ 28,224,031 |
| May-02 | $ 5,281,266 | $ (304,235) | $ 616,828 | $ 1,736,873 | $ 3,275,150 | - | - | - | $ 10,605,882 |
| Jun-02 | $ 5,849,346 | $ (2,009,412) | $ 596,930 | $ 6,328,364 | $ 4,934,370 | - | - | - | $ 15,699,599 |
| Jul-02 | $ 6,323,287 | $ 414,970 | $ 586,601 | $ 20,943,252 | $ 8,589,643 | $ 497,973 | - | - | $ 37,355,725 |
| Aug-02 | $ 6,657,998 | $ (456,021) | $ 601,665 | $ 16,832,670 | $ 4,641,022 | $ 18,514,264 | - | - | $ 46,791,597 |
| Sep-02 | $ 5,624,945 | $ 519,071 | $ 592,244 | $ - | $ 6,211,711 | $ 14,649,956 | - | - | $ 27,597,927 |
| Oct-02 | $ 4,752,112 | $ (6,683,587) | $ 617,225 | $ - | $ 5,130,228 | $ 5,606,320 | - | $ 17,100,961 | $ 26,523,258 |
| Nov-02 | $ 4,239,792 | $ (4,523,539) | $ 587,753 | $ - | $ 2,039,792 | $ 4,622,409 | - | $ 14,733,906 | $ 21,700,114 |
| Dec-02 | $ 4,682,990 | $ (4,710,083) | $ 605,743 | $ 116,804 | $ 1,545,486 | $ 4,620,579 | - | $ 15,910,038 | $ 22,771,558 |
| **Total** | **$ 86,938,192** | **$ 67,622,007** | **$ 7,191,881** | **$ 45,957,964** | **$ 76,844,302** | **$ 63,750,791** | **$ 7,206** | **$ 47,744,905** | **$ 396,057,248** |

### Congestion Rights

The TCR program officially began on February 15, 2002 to coincide with the direct assignment of zonal congestion costs. TCRs are defined as financial rights in one megawatt denominations for specific CSCs. A TCR entitles its holder to receive a payment equal to the shadow price on the corresponding CSC. To avoid the compounding of market power that could result from joint ownership of generation and transmission rights, QSEs are prohibited from holding more than 25% of the TCRs on any constrained corridor. About 20 percent of the available TCRs are specified as Pre-assigned Congestion Rights (PCRs) at reduced prices to municipally owned utilities and electric cooperatives that have grandfathered rights to the transmission system.

Sixty percent of the total annual quantity of TCRs less PCRs for any given CSC are awarded to market participants based on the results of an annual auction. Forty percent are awarded in monthly auctions. As required by the Commission in Docket No. 23220, ERCOT instituted a simultaneous combinatorial method for TCR auctions in December 2002. Market participants can exchange TCRs and PCRs in any secondary market. Neither TCRs nor PCRs are deratable.

The total TCR auction revenue was $91.1 million from February 15, 2002 to December 31, 2002; and the total TCR credit payments were $22.5 million. Thus, TCR auction revenues exceeded credit payments by about $68.7 million during 2002.

## Market Issues

### Overscheduling and BENA

When ERCOT began operation as a single control area on July 31, 2001, the costs for relieving zonal congestion were spread among market participants on the basis of load ratio share. This provided incentives for market participants to schedule generation across congested CSCs, knowing that they would likely receive more in payments to relieve that congestion than they would be assessed. When significant congestion occurred in August 2001, the costs for relieving it (as well as the costs for load imbalance, resource imbalance, and uninstructed deviation) were uplifted through the BENA which totaled $75.9 million for August.

Due to the high level of the BENA charges and the potential for gaming, MOD investigated the scheduling behaviors of market participants and found that six QSEs (AEP, Enron, Constellation, Mirant, Reliant, and TXU) received more than $2 million each in load imbalance revenues for the month of August. While the overscheduling did not appear to have contributed to high power prices, it allowed these companies to increase their revenues in the ERCOT settlement process, at the expense of other market participants. Ultimately, the Commission Staff and five of the six QSEs entered into settlements that resulted in refunds of $10,478,999 to other QSEs[12] that had been assessed BENA charges.[13] Staff reached a settlement with the sixth QSE, Enron, in March 2003 which calls for a penalty of $6,500,000 and a remittance of load imbalance payments in the amount of $2,900,000 to be refunded to other QSEs.

In the Order in Docket No. 23220, the Commission required ERCOT to switch to a direct assignment methodology by the earlier of January 1, 2003 or six months after zonal congestion costs exceeded $20 million. Direct assignment and a system of TCRs were implemented on February 15, 2002.

### Enron Strategies and the Potential for Gaming in ERCOT

Disclosure of the trading strategies used by Enron in California heightened the awareness of Texas regulators as to whether market rules could be exploited by generators, power marketers, or other wholesale market participants seeking to achieve exorbitant profits in the state's newly restructured electric market. MOD analyzed Enron's trading strategies and concluded that for the most part they could not be used in ERCOT because they were specific to California's market rules and the configuration of its electric grid. MOD presented its conclusions concerning the Enron strategies to the Legislative Oversight Committee (LOC) in June 2002. Although the Enron strategies could not be transferred, MOD's presentation to the LOC described six types of gaming that could occur in ERCOT and the actions that were being taken to mitigate the gaming potential.

Partly in response to the Enron strategies, the Commission directed the Staff to issue an information request to market participants to determine whether they had engaged in any of the Enron strategies, or variants thereof, and whether they had engaged in any contemporaneous purchase/sale transactions including "Wash," "Round Trip," "Bragawatt," or "Sell/Buyback" trades. Staff reviewed more than 175 responses from market participants, but they did not reveal widespread gaming of the ERCOT market.

### Rulemaking on Enforcement of Wholesale Market Rules

The letter that was sent to market participants for information concerning the Enron strategies also contained a section entitled "Certification of Ethical Conduct" in which respondents were

[12] In accordance with terms of the settlement, refunds were made to QSEs other than TXU.
[13] During settlement discussions it was determined that Constellation's scheduling activities did not harm the market so Constellation was not required to make refunds.

asked to certify that they would adhere to certain standards of conduct that were listed in the letter. Market participants objected, on the grounds that the standards had been developed without public input. The Commission then initiated a rulemaking to provide an opportunity for public input on a Code of Conduct. Almost immediately some market participants questioned the Commission's authority to develop a rule that prescribes wholesale market participants' behavior. In December 2002, the Commission responded by offering ERCOT stakeholders the opportunity to develop their own Code of Conduct. The Code of Conduct that was developed would have established certain behavioral standards to address concerns such as withholding of production and other market manipulations. Also, it would have been included in the Protocols and enforceable by the Commission. However, the stakeholders' proposal did not satisfy the Commission's desire for an enforceable Code of Conduct. The Commission then charged the Staff with developing an Enforcement Rule that would, among other elements, spell out the Commission's expectations regarding market participants' behavior, describe the standards and criteria to be used in investigating a market activity, and describe the process for conducting investigations. In July 2003 the Commission approved the draft rule for publication and invited public comments on it.

### Market Power Mitigation

Several actions were taken in 2002 that were specifically designed to mitigate market power in the provision of ancillary services. First, MOD proposed the Competitive Solution Method (CSM) in Docket No. 24770 to address situations where market prices rise to $1000 for reasons other than true market scarcity. The CSM proposal differs from automatic mitigation procedures used in other markets in that it does not evaluate individual bids against historical benchmarks. Instead, a two-part Competitive Sufficiency Test (CST) evaluates conditions in the market as a whole. The test specifies two conditions for the market to pass, but if it fails CSM specifies additional steps to determine the MCP. Second, ERCOT implemented a two-settlement system for the procurement of ancillary services. This addressed the situation where ERCOT opens a second market because it did not get enough bids in the first market. Under the two-settlement system, a separate MCPC is established for the second market which does not affect the prices for capacity acquired in the first market. Third, ERCOT implemented an 80% rule for periods of market insufficiency. To discourage withholding of offers to induce periods of bid insufficiency, a provision was added to the Protocols to pay the MCPC that would have resulted if ERCOT had procured only eighty percent of the capacity procured prior to the declaration of insufficiency. Finally, consistent with the Order in Docket No. 23220, the ERCOT Board approved a PRR for the simultaneous selection of ancillary services. Under sequential clearing in the original Protocols, a resource that was capable of providing a higher quality service such as Regulation could be selected to provide a lower quality service such as Responsive Reserve. This led to price reversals and gaming opportunities which could create artificial shortages of higher quality services.

Also in 2002, ERCOT implemented a Market Solution Test to address those situations when only a small number of generating units can provide Local Balancing Energy to resolve local congestion. The test provides that a Market Solution exists when "…at least three unaffiliated Resources, with capacity available, submit bids to ERCOT that can solve a circumstance of Local Congestion and no one bidder is essential to solving the Congestion." If a Market Solution exists, Local Balancing Energy is paid according to MCPE and unit specific bid premiums; if it does not exist, the energy is paid as OOME.

Stakeholders initiated several PRRs in 2002 that would reduce local congestion costs. In particular, a change was implemented to lower the cost of OOME. Whereas, OOM rates were initially set to allow the most expensive unit to recover its costs, the Protocols were changed to adopt several generation unit categories for OOME with technology-specific cost structures, thus lowering the cost of OOME deployment. Compensation for OOMC was also changed such that generating units are paid only for actual start-ups incurred, and these payments are also based on a set of generic generator characteristics. According to ERCOT's calculations, the changes in OOM reimbursement that were instituted on July 31, 2002 (PRRs 335-338) would have decreased OOME down payments to non-wind generators by 30% if they had been instituted at the ERCOT wholesale market opening on July 31, 2001.[14]

### Market Information Transparency

In order to improve market transparency and provide access to market information, MOD initiated a new PRR in early 2002 to limit the amount of information that could be designated as "protected information." In June 2002 the ERCOT Board approved PRR 327, which changed the way ERCOT defines and treats confidential information. Previously, market participants were permitted to self-declare any information as confidential, with some specific exceptions. The Protocols now specify the types of information that are protected and the length of time that each class of confidential information is to be protected. In addition to these changes, the Protocols now call for identifying QSEs if their bid prices are greater than $300 for Up Balancing or less than -$300 for Down Balancing. A list of such bidders for the entire operating day is published on the ERCOT web site the next day, although it does not specify bid quantities or prices. Another provision added by PRR 327 is recognition that the Commission may reclassify protected information as non-confidential after notification to the QSE and opportunity for appeal.

### Market Design Issues

Similar to zonal congestion, the Commission established a rolling twelve-month, $20 million threshold for direct assignment of local congestions rents. The threshold was reached on March 5, 2002, barely eight months after the market began. With the help of its senior advisor, Shmuel Oren, MOD developed a revenue neutral method for the assignment of local congestion fees. In this method generators are charged (or paid) congestion fees that are equal to their shift factor multiplied by the flow induced by their metered output (after congestion is relieved) on the congested intrazonal interfaces. The net zonal revenues or shortfalls resulting from the assignment of local congestion fees are allocated back to the generators in the zone on the basis of metered output on a *pro-rata* share. The proposed methodology can be viewed as an alternative way for implementing locational marginal cost prices which is designed to be ERCOT-friendly.

[14] *ERCOT Study on Local Congestion Costs*, as summarized by Dr. Eric S. Schubert, Market Oversight Division, PUC Project No. 26376 (filed January 10, 2003).

After much discussion, market participants have raised various objections to MOD's proposal, and no consensus has emerged on any specific method for assigning local congestion costs. Although MOD's proposal was intended to preserve the zonal system, MOD and various market participants have questioned whether a different market design would be more suited to ERCOT's needs in the long run. The level of local congestion costs is unacceptably high, and it is apparent to MOD that the existing Protocols contain incorrect incentives which encourage market participants to play the DEC game, thereby increasing congestion costs. It is also apparent that the lack of locational price signals within a zone encourages developers to build new resources in locations that exacerbate congestion costs and result in unnecessary transmission costs. Standard economic theory states that the most efficient way to allocate scarce resources such as transmission capacity is to use marginal pricing.

In November 2002 the Commission began a series of workshops focused on transmission congestion and market design issues. The activity is being conducted in Project No. 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas.* Three workshops have been held in which a variety of issues have been addressed. Review and debate of market design issues is continuing in 2003.

### Resource Plan Accuracy

Each QSE must submit a Resource Plan to ERCOT in the day ahead which shows the availability of its resources along with the planned operating levels and limits of these resources. Although designed as a planning tool, the Resource Plan has become critical for real-time operational purposes and financial settlement. Reliance on the Resource Plan for operational information is a by-product of the portfolio based market design that distinguishes ERCOT from other markets. Difficulties have emerged however, because the Resource Plan was not designed to be readily updated near real-time, and ERCOT systems do not have the ability to efficiently track QSE changes to Resource Plans. As a result ERCOT does not have the proper tools to track available capacity and unit offline status, to properly assess the operational characteristics of generating units and load resources, and to know with certainty how individual resources are going to be operated.

PRR 359 was introduced to improve information in the plan on resource operating limits, but it does not solve all of ERCOT's operating problems. In addition, ERCOT introduced a proposal to measure QSEs' Resource Plan performance. The performance metrics were tested in the first half of 2003, and discussions are underway between ERCOT staff and stakeholders on ways to adjust and refine them.

### Relaxed Balanced Schedule

The Balanced Schedule requirement in the original Protocols was intended to preclude QSEs from relying on the ERCOT-administered balancing energy market as part of their resource portfolios. However, with an eye toward increasing the liquidity of forward energy markets, the Commission adopted MOD's recommendation in Docket No. 23220 that ERCOT should consider and report on the technical implications of relaxing or eliminating the Balanced Schedule requirement. After studying the issue and addressing ERCOT's concerns about frequency control and keeping Resource Plans accurate and up-to-date, the Balanced Schedule

Working Group recommended the adoption of a Relaxed Balanced Schedule (RBS) requirement. Under RBS, a QSE must schedule the amount of resources that it intends to provide in every interval in the next 24-hour period. For each resource amount, it must also schedule an equal amount of load, even though the scheduled load may not correspond exactly to the QSE's forecasted requirements.

RBS was implemented on November 2, 2002. In the first two months of implementation, there did not appear to be any effect on balancing energy deployments, frequency control, or the required level of Day-ahead capacity reserves. MOD continues to monitor the effect of RBS implementation on the market.

### McCamey Area Transmission Constraints

So much wind power has recently been added in the McCamey area that the wind generation capacity is almost twice the area's transmission export capacity. Local congestion costs, caused by curtailment instructions to wind generators, amounted to around $9 million for all of 2002. Several wires companies are constructing and upgrading lines to alleviate transmission constraints, but capability will continue to fall short of existing wind generation through 2006. MOD believes that planning will be a crucial part of a transmission solution.

Wind farms that were curtailed due to transmission limitations were compensated for the power not generated and the value of lost tax credits and renewable energy credits. MOD supported Protocol changes that would have eliminated curtailment payments and directly assigned congestion rent to those who cause congestion. ERCOT stakeholders rejected a MOD proposal to establish a McCamey congestion management zone, but they did agree to develop a special congestion management regime for wind farms in the area in which curtailment payments are strictly limited and available transmission capacity is apportioned in a manner akin to water rights. MOD will monitor the results of the McCamey congestion management plan in 2003.

### Demand Resources

The ERCOT Protocols allow for loads to participate in the ERCOT administered markets as either Loads acting as Resources or Balancing Up Loads (BULs). By the end of 2002, 570 MW of LaaRs were actively bidding in that market, with over 300 MW more load resources in the process of being certified by ERCOT. BULs participation will be technically possible as of June 2003; and small loads will also have an opportunity to participate in the markets when Direct Load Control (DLC) programs are in place.

In May 2002, MOD retained a third party independent consultant to review the existing programs and market rules, identify barriers to load participation, and make recommendations for modifications to rules and programs to facilitate the participation of load resources in the balancing energy market and the ancillary services markets. In addition, MOD suggested that a training program be developed by ERCOT, targeting large customers and Retail Electric Providers (REPs), in order to explain the intricacies of load participation in the ERCOT markets. MOD Staff also suggested that ERCOT hire a demand-side expert to interface with QSEs representing load resources and with the Demand Side Working Group. Both recommendations have been implemented.

### Resource Expansion and Mothballed Units

More than 19,000 MW of new generating capacity was built in ERCOT between 1995 and the end of 2002, and there was another 5,800 MW of capacity under construction at the end of 2002. The new capacity includes "switchable" generation (1675 MW installed, 1220 MW under construction) which can be switched back and forth between ERCOT and SERC or SPP. ERCOT's most recent five-year projection (May 2003) indicates that reserve margins will be in the range of 30 to 40% through 2008. MOD does not entirely agree with these projections; however, it is likely that ERCOT will continue to have ample reserve margins for several years to come.[15]

**Projected ERCOT Reserve Margins**

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|
| Capacity (MW) | 78,715 | 83,206 | 83,523 | 85,892 | 85,892 | 85,892 |
| Firm Demand (MW) | 56,925 | 58,366 | 59,843 | 61,357 | 62,908 | 64,499 |
| Reserve Margin (%) | 38.3% | 42.6% | 39.6% | 40.0% | 36.5% | 33.2% |

ERCOT is becoming more dependent on natural gas since virtually all of the new generating capacity, except for wind and other renewable resources, is gas fired. This dependence is made more critical by the fact that most of the new generation does not have dual fuel capability because the developers determined that it was not economic to include it.

**Generating Capacity by Energy Source in 2003[16]**

| | Natural Gas | Coal | Nuclear | Wind | Hydro | Other | Total |
|---|---|---|---|---|---|---|---|
| Capacity (MW) | 59,147 | 15,133 | 4,737 | 941 | 552 | 412 | 80,922 |
| Percent of Total | 73.1% | 18.7% | 5.9% | 1.2% | 0.7% | 0.5% | 100% |

In 2002 both American Electric Power (AEP) and Reliant Resources (Reliant) announced that some of their older, gas-fired units would be mothballed. ERCOT determined that some of the AEP units were needed in the last quarter of 2002 for reliability purposes. Mothballed and switchable generation units present a challenge for long-term planning purposes because it will be difficult to project how much of their capacity will be available in ERCOT in future years.

### Reliability-Must-Run

ERCOT contracted with AEP and Frontera for 1,718 MW and 150 MW, respectively, of RMR service in the last quarter of 2002. The cost was $32.0 million which was uplifted to QSEs on a load ratio share basis. Units contracted to provide RMR are compensated for start-up and energy costs, and they are paid a standby price.

[15] MOD's reservations concerning the capacity projections were presented in the Commission's Open Meeting on June 18, 2003 in PUC Project No. 24255. If it is assumed that only 50% of switchable capacity, DC Ties, LaaRs, and none of the recently mothballed capacity would be available, the reserve margins would range from about 33% in 2004 to about 23% in 2008.

[16] The 2003 value for capacity includes mothballed capacity which is not reflected in the reserve margin calculation.

**Net Cost for RMR in 2002 by Local Area (Million $)**

| Local Area | Zone | Net Costs |
|---|---|---|
| Corpus Christi | South | $9.8 |
| Laredo | South | $4.0 |
| Valley | South | $11.5 |
| Abilene Area | West | $3.2 |
| West (Rio Pecos & San Angelo) | West | $3.6 |
| | **Total** | $32.0 |

Due to the high level of RMR costs incurred, ERCOT stakeholders formed a task force to review RMR compensation and determine if there were alternatives to the existing OOM and RMR Protocols. The work of the task force continues in 2003.

## Resource Adequacy

In a competitive market no specific level of reserve capacity is assured. In view of the risk for high prices and supply disruptions if there is not adequate reserve capacity, the Commission initiated a rulemaking to establish a minimum planning reserve margin level and a mechanism for maintaining that level. MOD held four workshops in 2002 to identify key issues and discuss various mechanisms that could be used to provide reserve capacity. It also participated in the ERCOT Generation Adequacy Work Group (GAWG) which evaluated two reserve margin mechanisms in detail, one proposed by Reliant and the other by LCRA. Both mechanisms employed a centralized auction through which ERCOT would procure reserve capacity, but they differed in terms of (1) the quantity of resources to be procured in the auction, (2) which resources could set the auction clearing price, (3) the time period for which capacity would be procured, and (4) the number of hours the capacity would be subject to call by ERCOT.

MOD developed a strawman for the rulemaking based on the Reliant model but with several modifications. The strawman was the subject of a workshop held in December. Much of the discussion focused on (1) whether there was a need for physical self-arrangement of reserve capacity, (2) whether there was a need for a call option on reserve capacity, (3) what the impact of high availability requirements would be, and (4) what the potential for higher costs as a result of the reserve requirement and centralized auction would be. Debate on reserve margin issues is continuing.

# I. INTRODUCTION

This is the first annual report prepared by the Market Oversight Division (MOD) of the Public Utility Commission of Texas (PUC or Commission). It actually covers the first 17 months of wholesale market activities in the Electric Reliability Council of Texas (ERCOT) from July 31, 2001 to December 31, 2002. The wholesale market in Texas was opened to competition by the Legislature in 1995, but it was not until the historic transition in ERCOT from ten control areas operated by vertically integrated utilities to a single control area operated by an independent organization that a centralized market focused on competition was created. Shortly after the transition to a single control area, the retail market was opened to competition on January 1, 2002. Since its creation in September 2000, MOD has been actively involved in ERCOT Protocol issues, market design issues, and market monitoring activities. This report provides an overall review of market performance in the first 17 months and a summary of the key issues and activities with which MOD has been involved.

The ERCOT Protocols were developed by stakeholders and approved by the Commission in Docket No. 23220 on June 4, 2001.[17] The Commission's Order on Rehearing addressed many issues that had been raised during the Protocol development period, including several issues in ancillary services and congestion management. In addition, the Commission recognized that some elements of the market design and market operating systems had not yet been fully developed and implemented, so the Order established a timeline for the completion of these activities. The timeline required ERCOT to file certain reports and recommendations, by October 1, 2001, on several wholesale market issues regarding the implementation of the ERCOT Protocols and the development of the ERCOT market model. When it was filed, the report was assigned Docket No. 24770.[18] Many of the issues that MOD addressed in the first 17 months of the market were related to ensuring compliance with the Order on Rehearing in Docket No. 23220 and addressing the additional issues that were covered in Docket No. 24770. MOD's activities in 2002 included a "lessons learned" workshop[19] after the first year of market operation and an additional workshop on ERCOT operational problems[20] and solutions.

Section II of this report provides a statistical summary of the ancillary services markets for the first 17 months of market operation. As the system operator responsible for reliability, ERCOT operates a Day-ahead market and an Operating Period market to obtain capacity ancillary services and balancing energy service.

ERCOT uses a zonal congestion management system with Commercially Significant Constraints between the zones. Section III summarizes the interzonal ("interzonal" or "zonal") congestion costs, intrazonal ("intrazonal" or "local") congestion costs, and the results of the auctions for

[17] *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, Docket No. 23220, Order on Rehearing, June 4, 2001.
[18] *Report of the Electric Reliability Council of Texas Regarding Certain Market Design Issue*, Docket No. 24770 (pending).
[19] *Lessons Learned: Evaluation of the Performance of the ERCOT Wholesale Market*, Project No. 26330, workshop held on July 23, 2002.
[20] *ERCOT Operational Problems and Solutions*, Project No. 26331, workshop held on October 18, 2002.

Transmission Congestion Rights that market participants can acquire to hedge their interzonal congestion costs.

Section IV presents a series of market issues that occurred during the first 17 months.

Significant overscheduling of load and resources occurred in the first month of market operation, August 2001. Section IV.A describes the conditions that led to overscheduling and the investigation that MOD undertook which resulted in refunds of $10.5 million to the market for Balancing Energy Neutrality Adjustment charges.

Then Enron gaming strategies were disclosed in 2002, but MOD's analysis indicated that they could not be readily applied in ERCOT. Nonetheless, Section IV.B summarizes the potential for gaming in ERCOT, and provides a list of measures that have been or are being taken to mitigate gaming. Partly in response to the Enron gaming strategies, the Commission initiated a rulemaking on enforcement of wholesale market rules. It is described in Section IV.C.

Several actions were initiated in 2002 to mitigate market power in the ancillary service and balancing energy markets and to reduce intrazonal congestion costs. These actions, which include MOD's Competitive Solution Method, are described in Section IV.D.

Although ERCOT was required in 2002 to implement direct assignment of local congestion costs, no agreement was reached on the best methodology to accomplish it. The debate over local congestion expanded to a much broader debate over the best market design for ERCOT, viz., zonal or nodal with locational marginal pricing. The market design issues are introduced in Section IV.F, but they continue as a major activity in 2003.

As market operations progressed in 2002, it became apparent that the Resource Plan is vital to ERCOT for real-time operations and financial settlements. Section IV.G describes the key role it plays and some of the steps being taken to ensure that the information is as accurate and up-to-date as possible. Another key operational issue in 2002 was implementation of the Relaxed Balanced Schedule. It is discussed in Section IV.H along with initial results after implementation.

Section IV.J describes the demand resource programs that were added to the Protocols in 2002, viz., Loads acting as Resource and Balancing Up Loads. It also summarizes a consulting study for MOD on demand-side resources and price responsiveness in the ERCOT market.

Section IV.K provides information about new generating resources in ERCOT, along with ERCOT's five-year projection of reserve margins. ERCOT entered into several Reliability-Must-Run contracts in 2001-2002, and Section IV.L provides a list of the contracted units and a summary of the payment components.

MOD held several workshops in 2002 concerning a rulemaking to establish a reserve margin requirement. MOD's strawman for the rule and some of the reserve margin mechanisms that were suggested are summarized in Section IV.M.

# II. ANCILLARY SERVICE MARKETS

The majority of load in the ERCOT region is served through bilateral transactions or generation with native load, but ERCOT deploys ancillary services in order to maintain the security and reliability of the transmission system in accordance with ERCOT standards and the standards of the North American Electric Reliability Council (NERC). The ERCOT Protocols define eleven ancillary services, including five capacity services which are acquired in the Day-ahead market and balancing energy services which is acquired during the Operating Period approximately 20 minutes before the time of actual power flow.[21]

## A. Capacity Ancillary Services

The five capacity ancillary services acquired in the Day-ahead market are described below:

- **Regulation Up Service ("Regulation Up" or URS)** and **Regulation Down Service ("Regulation Down" or DRS) –** Regulation service is used to control the power output of generation resources in response to a change in system frequency so as to maintain the target system frequency within predetermined limits. It is deployed instantaneously through automatic generation control.

- **Responsive Reserve Service ("Responsive Reserve" or RRS) –** Daily operating reserves that are intended to help restore the frequency of the transmission system within the first few minutes of an event that causes a significant deviation from the standard frequency. It is deployed within ten minutes and can be provided by unloaded generation on line, high-set underfrequency relay (limited to 35% of RRS), and DC Tie response.

- **Non-Spinning Reserve Service ("Non-Spinning Reserve" or NSRS) –** A service provided by off-line generation capacity or interruptible load that is capable of reaching a specified output level within 30 minutes and remaining at that level for at least one hour. On-line capacity that is not participating in any other service or activity can also provide NSRS.

- **Replacement Reserve Service ("Replacement Reserve" or RPRS) –** A resource specific service procured from off-line generation resources and Loads acting as Resource (LaaRs) that are available during the period of requirement. The service is procured to provide Balancing Energy Service for system deficiencies and congestion management.

In the first 17 months of the market ERCOT required fixed amounts of URS, DRS, and RRS for each hour of the day. NSRS and RPRS were required on an as-needed basis. The following table summarizes the required amounts of each service.

[21] The other capacity ancillary services are Voltage Support Service, Black Start Service, Reliability-Must-Run Service, Out-of-Merit Capacity Service, and Out-of-Merit Energy Service.

**Table 1: Required Amounts of Capacity Ancillary Services**

| Ancillary Service | Amount Per Hour | Hours Per Day |
|---|---|---|
| **Regulation Up** | 1200 MW[22] | 24 |
| **Regulation Down** | 1800 MW | 24 |
| **Responsive Reserve** | 2300 MW | 24 |
| **Non-Spinning Reserve** | 1250 MW | As needed |
| **Replacement Reserve** | As needed | As needed |

In the remainder of this section, the term "ancillary services" refers only to the first four capacity services described above. Replacement Reserve was procured only on rare occasions during the first 17 months so it is not included in the discussion unless specifically identified.

ERCOT assigns responsibility for providing the URS, DRS, RRS, and NSRS services to Qualified Scheduling Entities[23] (QSEs) on the basis of their historical load ratio shares. A QSE can self-arrange its ancillary service obligations, or it can designate ERCOT to procure ancillary services on its behalf in the Day-ahead market. QSEs cannot self-arrange RPRS, and ERCOT procures all of this service from the market when it is needed.

QSEs submit their schedules for self-arranged services in the Day-ahead market (Figure 1). They also submit bids for ancillary services that they would supply to the market if selected by ERCOT. ERCOT purchases ancillary services and posts the Market Clearing Price of Capacity (MCPC) for each service. Following the Day-ahead market, QSEs can adjust their schedules and bids throughout the Adjustment Period, i.e., up to one hour before the Operating Hour. Based on its analysis of schedule changes, Resource Plans, load forecasts, and other system conditions, ERCOT may open additional markets during the Adjustment Period to procure additional ancillary services.

**Figure 1: ERCOT Market Timeline**

| 6:00 AM – 6:00 PM | | 1 Hour | |
|---|---|---|---|
| **Day Ahead Market** | **Adjustment Period** | **No Adjustments** | **Operating Hour** |
| | | **Operating Period** | |

## 1. Self-Arrangement

In the first 17 months of the market, QSEs relied primarily on self-arrangement of ancillary services; however, there was a gradual increase in the level of these services procured by ERCOT (Figure 2). In September 2001 ERCOT procured 3.2% of its ancillary service requirements, but the percentage grew to 20% by July 2002. The average for all services was 10.2% for the five months in 2001 and 19.4% for year 2002 (Table 2). The average procurement for 2001 was affected by the month of August in which ERCOT procured 30.9% of ancillary services. August was the first month of the market, but it was atypical of the pattern established

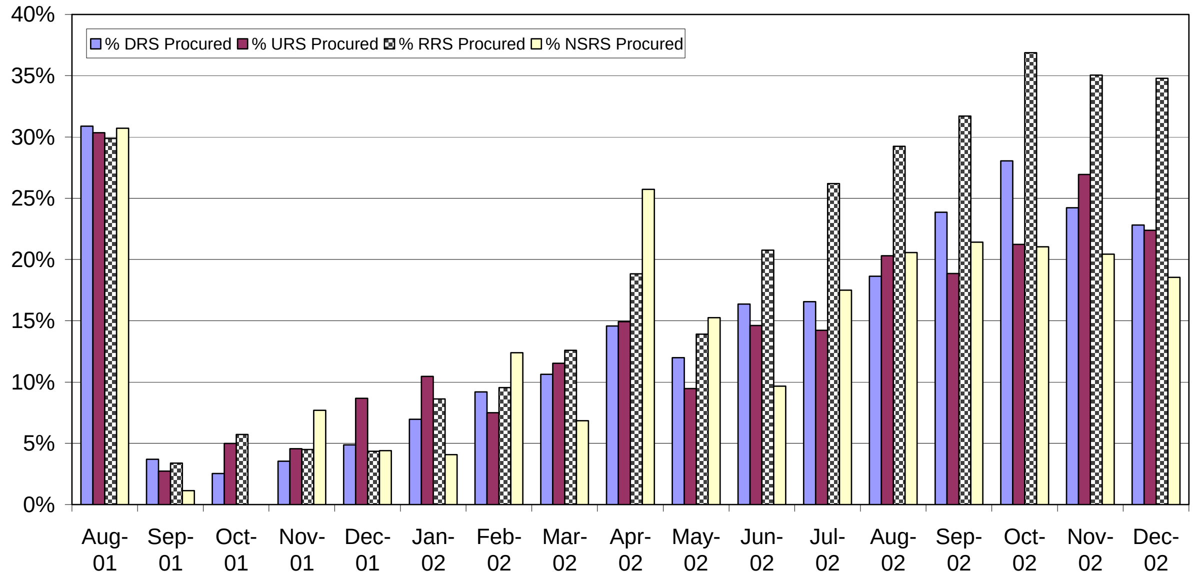
[22] The URS requirement was 1800 MW from August through September 2001.
[23] Resources (and load serving entities) must be represented by QSEs in scheduling and settlement with ERCOT.

in September 2001. If August were removed from the data, the average ERCOT procurement for 2001 would have been 4.3%. The trend from September 2001 to December 2002 toward greater procurement of ancillary services by ERCOT implies that QSEs became more willing to rely on the market to provide these services at a cost that was equal to or less than the cost of providing the services from their own resources or acquiring them bilaterally.

**Table 2: Percent of Ancillary Services Procured by ERCOT**

| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve | Total |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | 11.0% | 9.2% | 9.7% | 19.7% | 10.2% |
| **2002** | 16.1% | 17.0% | 23.3% | 17.3% | 19.4% |

**Figure 2: Percent of Ancillary Services Procured by ERCOT**




## 2. Bid vs. Struck Capacity

ERCOT Protocols allow the same capacity to be bid for multiple ancillary services, even though it can be selected for only one service. This contributed to the high level by which bids for ancillary service exceeded the amount procured by ERCOT. Table 3 shows the difference in megawatts between the average hourly amount that was bid and the average hourly amount that was procured. Even though the percentage of ancillary services purchased by ERCOT steadily increased during 2001 and 2002, the data show that the level of bidding remained high in relation to the amount of capacity procured.

**Table 3: Average Hourly Bid and Struck Capacities for Ancillary Services (MW)**

| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve |
|---|---|---|---|---|
| **2001 (Aug-Dec) Bid** | 921 | 877 | 961 | 1069 |
| **2001 (Aug-Dec) Struck** | 173 | 168 | 225 | 96 |
| **2001 (Aug-Dec) Difference** | 748 | 709 | 736 | 973 |
| | | | | |
| **2002 Bid** | 916 | 1201 | 1286 | 896 |
| **2002 Struck** | 186 | 296 | 535 | 93 |
| **2002 Difference** | 730 | 905 | 751 | 803 |

### 3. Ancillary Service Prices

Table 4 shows the annual weighted average prices for ancillary services in the first 17 months of market operation.

**Table 4: Weighted Average Prices for Ancillary Services ($/MW)**

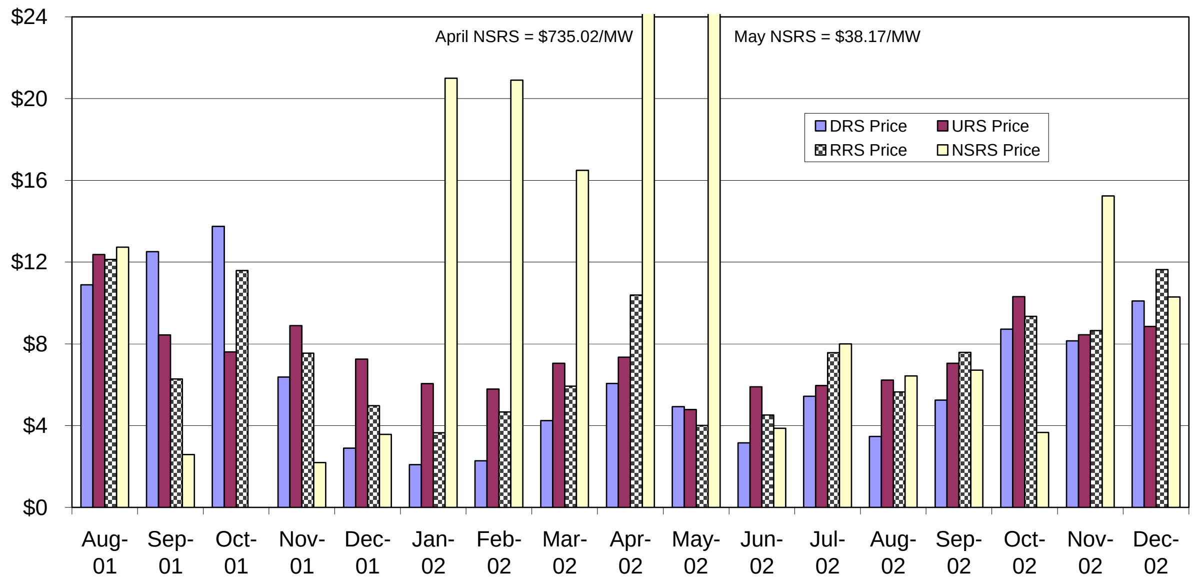
| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve | Total |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | $10.80 | $9.97 | $10.59 | $12.40 | $10.59 |
| **2002** | $7.38 | $6.07 | $7.76 | $35.18 | $8.23 |

In comparison to New York and California, ERCOT regulation prices tended to be lower, but the spinning and non-spinning reserve prices tended to be higher. In 2002 the ancillary service prices in California were $13.41/MW for regulation up, $13.76/MW for regulation down, $4.66/MW for spinning reserve, and $2.15/MW for non-spinning reserve.[24] The California prices include both day-ahead and hour-ahead markets so they are not exactly comparable to the ERCOT Day-ahead market prices. In New York, the monthly average price for regulation in the day-ahead market ranged from about $12/MW to $24/MW.[25] New York has three categories of operating reserves (10-minute spinning reserve, 10-minute total reserve, and 30-minute reserve), and all but one of the monthly average prices in 2002 were less than $5/MW.

The weighted average prices are shown on a monthly basis in Figure 3. The price for Non-Spinning Reserve in April 2002 was dramatically affected by a price spike that occurred on April 30th. ERCOT procured NSRS on only the last three days in April, which were days when temperatures were predicted to be high. On the 30th, ERCOT procured NSRS in only 12 intervals, but the MCPC in each interval was $990-$999/MWh. Without the 30th, the April price for NSRS would have been much lower, although it still would have exceeded $100/MW because the MCPC exceed $100/MW in five intervals on April 29th. May was also a high price month for NSRS; the highest interval MCPC was $150/MW.

24 "2002 Annual Report on Market Issues and Performance," California Independent System Operator, April 2003, p. 5-10.
25 "2002 State of the Market Report – New York ISO," Potomac Economics, Ltd., Independent Advisor to the New York ISO, June 2003, p 3.

**Figure 3: Weighted Average Price for Ancillary Services ($/MW)**




ERCOT ancillary services frequently exhibited price reversals in 2001 and 2002. A price reversal occurs when the MCPC for a less valuable service such as Responsive Reserve is higher than the MCPC for a more valuable service such as Regulation Up. Price reversals can occur when the same capacity is bid for more than one service and the market clearing prices are determined sequentially. To address this issue, the Commission ordered simultaneous selection of ancillary services in Docket No. 23220. In January 2003, the ERCOT Board of Directors approved Protocol Revision Request (PRR) 342 which will implement simultaneous selection for Regulation Up, Regulation Down, and Non-Spinning Reserves.

## 4. Cost for Ancillary Services

The total cost for ancillary services procured was $23.4 million in 2001 (Aug-Dec) and $77.6 million in 2002 (Table 5). Seventy-five percent of the cost in 2001 was incurred in August when ERCOT procured more than 30% of its ancillary service requirements from the market. In 2002, 48% of the cost was incurred in only three months, April, October, and December.

**Table 5: Total Cost of Ancillary Services[26]**

| | Regulation Up | Regulation Down | Responsive Reserve | Non-Spinning Reserve | Total |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | $6,852,987 | $6,141,615 | $8,744,232 | $1,687,244 | $23,426,077 |
| **2002** | $12,504,806 | $16,335,654 | $36,439,136 | $12,317,824 | $77,597,420 |

Also in 2002, Regulation accounted for 37.1% of the cost (16.1% for Regulation Up and 21.0% for Regulation Down), Responsive Reserve accounted for 47.0%, and Non-Spinning Reserve

[26] Costs are based on ERCOT Day Ahead Reports and may not correspond directly to financial settlements.

accounted for 15.9%. The cost for Responsive Reserve was significantly higher than any of the other services in the last six months of the year. April was the highest cost month of the year due to the NSRS price spike that occurred on April 30th. The resulting cost for NSRS on that day was $7.9 million.

## B. Balancing Energy Service

ERCOT acquires balancing energy as an ancillary service to make up the difference between actual electricity requirements and the sum of base energy schedules submitted by QSEs. Balancing energy is also used to manage transmission congestion and to minimize the net energy needed in real time from regulation service. Balancing Energy Service consists of Up Balancing Energy Service (Up Balancing or UBES) and Down Balancing Energy Service (Down Balancing or DBES). QSEs must bid 15% of their scheduled generation as Down Balancing, but there are no specific obligations for Up Balancing bids. QSEs cannot self-arrange balancing energy. Balancing energy bids are capped at $1000/MWh or ($1000)/MWh.

QSEs submit balancing energy bids by the end of the Adjustment Period (Figure 1). The bids are submitted by zone, and they include a ramp rate to increase or decrease generation above or below the level shown in the QSE's balanced energy schedule. The bid stack is fixed for the Operating Hour, but balancing energy is deployed in 15-minute intervals. The market clears 20 minutes prior to the operating interval, based on projections obtained using short-term forecasting tools. Bids are accepted in ascending order of price until the total quantity required is obtained. The bid price of the last quantity accepted for Balancing Energy Service sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval.

A positive bid for Up Balancing is the dollar amount that a QSE would require in order to increase generator output, and a positive bid for Down Balancing is the amount that a QSE would pay ERCOT to serve the QSE's load, thereby allowing the QSE to reduce its generator output. A QSE can also bid a negative price for Down Balancing which would represent the amount the QSE would expect to be paid to reduce its generator output, recognizing that ERCOT would also assume responsibility, both operational and financial, for serving the load that was served by the reduced generation. If a sufficient number of negative bids are submitted, it may result in a negative MCPE. Down Balancing and Up Balancing are cleared simultaneously. Since Down Balancing bids can offset Up Balancing bids, there is a net savings to the market. Both Down Balancing and Up Balancing can be cleared in the same interval.

### 1. Deployments

Balancing energy accounts for only a small percentage of the total energy in ERCOT (Table 6). On a monthly basis, the Down Balancing percentages in the first 17 months ranged from 0.7% to 3.2% and the Up Balancing percentages ranged from 0.4% to 2.4%. In the first ten months of the market, the percentage values changed significantly from month to month, but in the last eight months of 2002 they tended to be more stable.

**Table 6: Balancing Energy as a Percentage of Total ERCOT Energy**

| Month | ERCOT Energy | DBES MWh | UBES MWh | DBES % | UBES % |
|---|---|---|---|---|---|
| **2001 (Aug-Dec)** | 114,580,051 | (2,389,096) | 913,115 | 2.09% | 0.80% |
| **2002** | 279,542,465 | (4,505,691) | 4,653,143 | 1.61% | 1.66% |

The relative amounts of Down Balancing versus Up Balancing energy deployed also changed significantly from month to month during the first 17 months of the market (Figure 4). For example, in the months of February through June 2002, ERCOT deployed more Down Balancing than Up Balancing, so the net deployment of balancing energy was Down Balancing. This trend was reversed in the last half of 2002 when the net deployment was Up Balancing. When the Relaxed Balanced Schedule (see Section IV.H) was implemented in November 2002, it was anticipated that balancing energy deployments could be affected since schedules had to accurately represent generation but not necessarily load. However, Figure 4 shows that there was no significant change in balancing energy deployments in the last two months of 2002.

### 2. Balancing Energy Prices

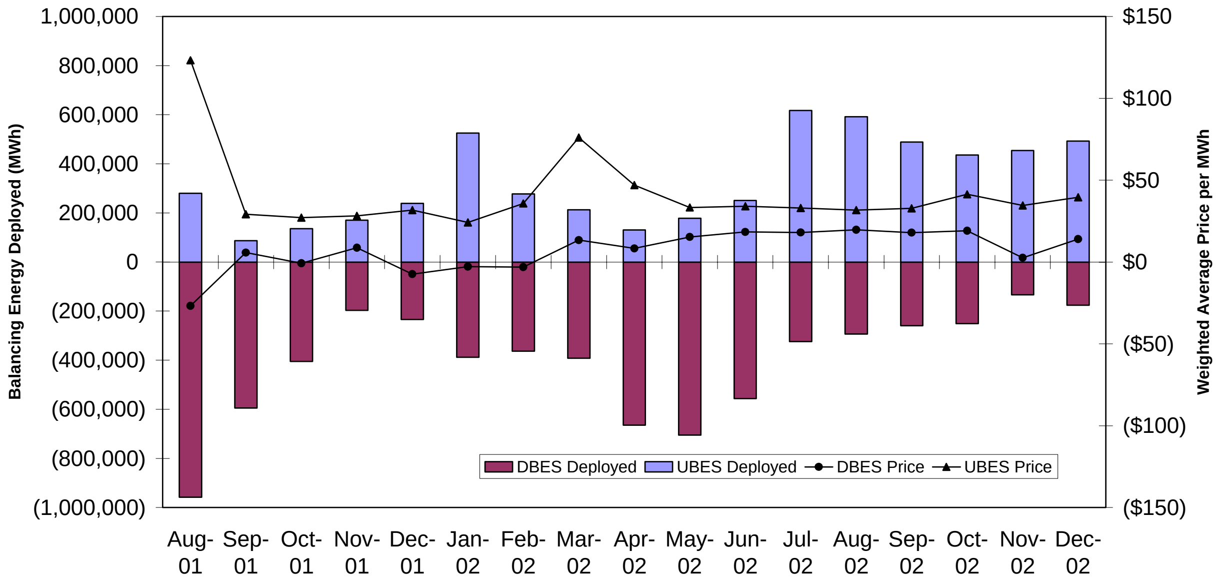
The weighted average prices for balancing energy are shown in Table 7. The negative value for Down Balancing in 2001 indicates that on average ERCOT paid generators to reduce their output, whereas the positive value in 2002 indicates that QSEs paid ERCOT so they could reduce their output. In both cases, ERCOT served the load that the reduced generation would have served.

**Table 7: Weighted Average Balancing Energy Prices ($/MWh)**

| | Down Balancing | Up Balancing | Total |
|---|---|---|---|
| **2001 (Aug-Dec)** | ($9.44) | $58.22 | $22.93 |
| **2002** | $11.86 | $36.03 | $12.47 |

Figure 4 shows the weighted average prices on a monthly basis, along with total deployments. The Up Balancing prices were in the range of $24 to $47/MWh in all months except March 2002 and August 2001 when the monthly average prices reached $76.09/MWh and $123.29/MWh, respectively. The monthly prices for Down Balancing ranged from about ($7) to about $20/MWh, except in August 2001 when they reached ($26.82)/MWh. The balancing energy prices and deployments in August 2001 were affected by a combination of peak period consumption levels and uplift provisions in the original Protocols that created incentives to schedule generation across congested interfaces (see Sections III.B, III.D, and IV.A). This resulted in substantial deployments of Down Balancing in the South Zone and high prices for Up Balancing, especially in the North and West Zones (Figure 8). In March 2002, Up Balancing prices reached $999/MWh in 40 intervals on March 2 and 9. These prices occurred in all zones on March 2 and in the West Zone on March 9.

**Figure 4: Balancing Energy Deployments and Weighted Average Prices by Month**

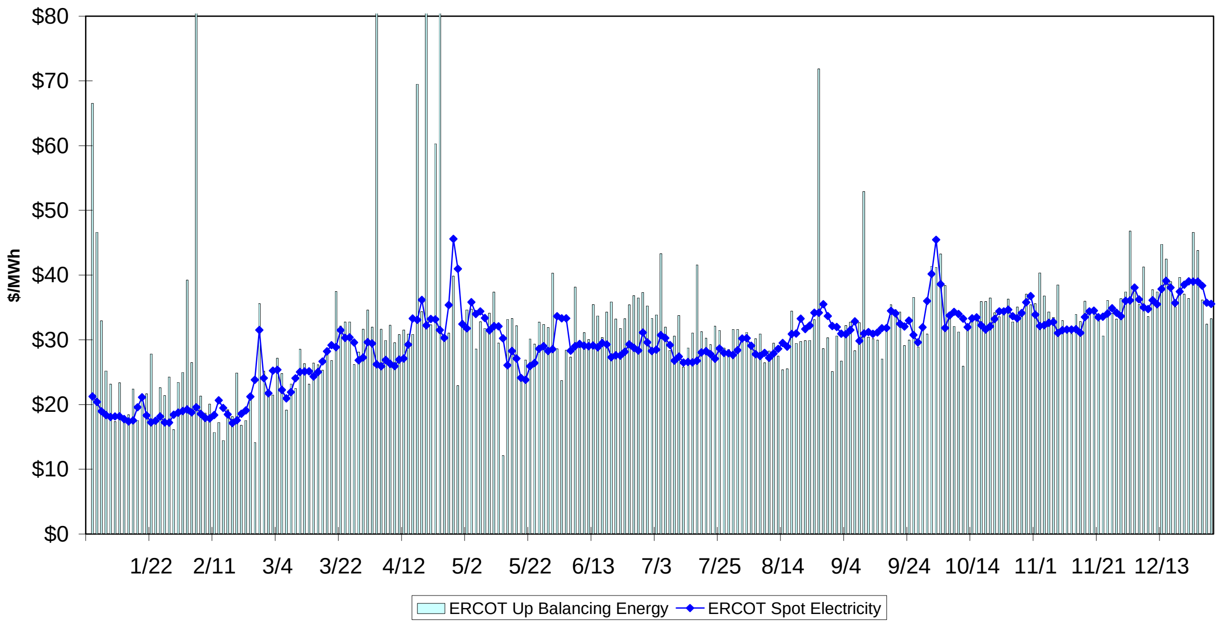



In 2002, the ERCOT average prices for balancing energy were sometimes lower and sometimes higher than California and New York. In California the average price for incremental energy (INC) was $53.04/MWh versus $36.03/MWh in ERCOT, but the average price for decremental energy (DEC) was $8.79 versus $11.86/MWh in ERCOT.[27] In New York, imbalance energy is paid at the Real-Time Locational-based Marginal Price (RT-LBMP) and the price is determined by zone. In 2002 the RT-LBMP was $48.55/MWh in New York City, $38.99/MWh in the Capital Zone, and $31.37 in the West Zone.[28]

The ERCOT Up Balancing price can also be compared to the ERCOT spot price for electricity. As shown in Figure 5, the Up Balancing price generally matched the spot price in 2002 as reported in Megawatt Daily, although the Up Balancing price tended to be much more volatile.

[27] "2002 Annual Report on Market Issues and Performance," California Independent System Operator, April 2003, p. 4-3.
[28] "2002 State of the Market Report – New York ISO," Potomac Economics, Ltd., Independent Advisor to the New York ISO, June 2003, p 6.

**Figure 5: Comparison of Up Balancing Price and Spot Price for Electricity in 2002**[29]




Since ERCOT generation is now more than 70% gas-fired, ERCOT energy prices are significantly impacted by changes in the price of natural gas. In 2002, natural gas prices at the Houston Ship Channel doubled from about $2.25/MMBTU in January to about $4.50/MMBTU in December. At the same time, Up Balancing prices went from about $24/MWh in January to about $39.50/MWh in December (Figure 6).

[29] ERCOT spot prices as reported in Megawatt Daily. Data do not include weekends and holidays.

**Figure 6: Comparison of Up Balancing Price and Spot Price for Natural Gas in 2002[30]**

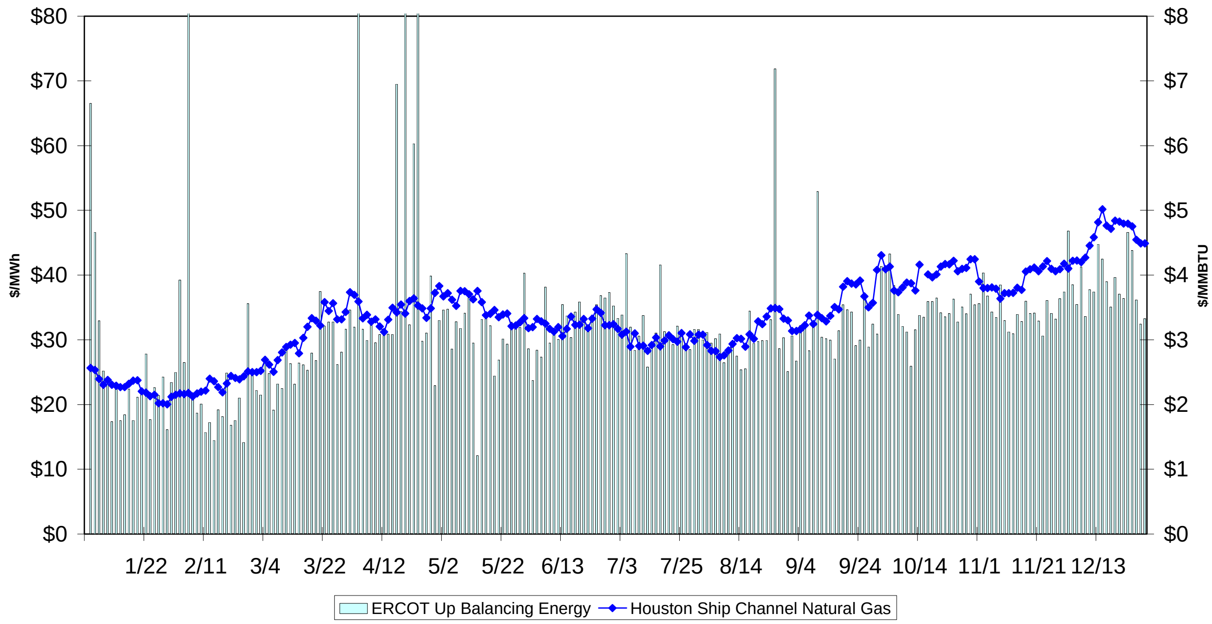



Table 8 shows the weighted average prices on a zonal basis.

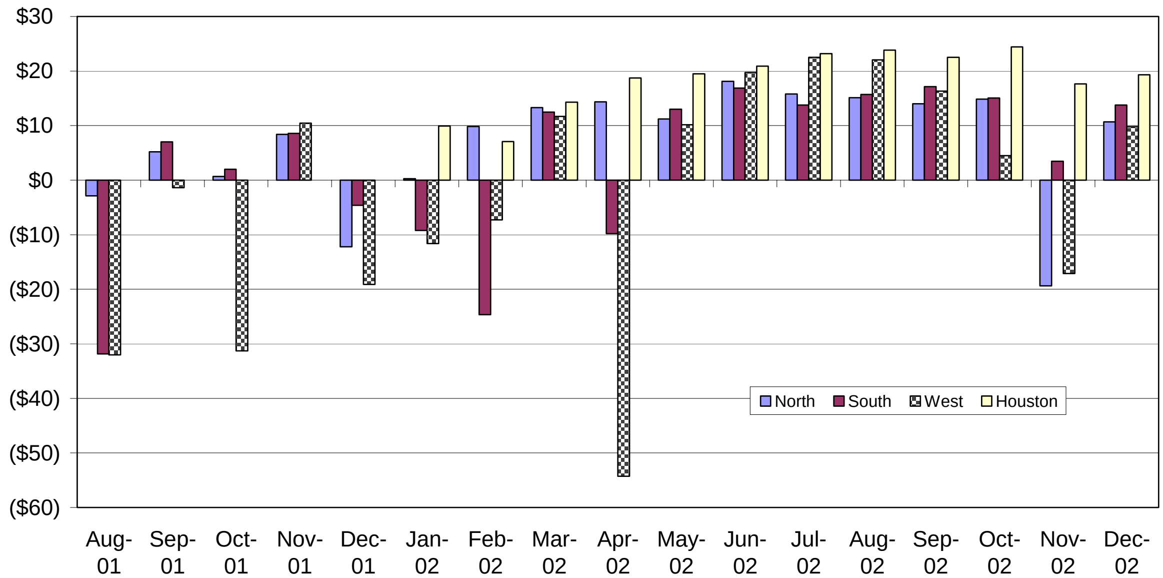
**Table 8: Weighted Average Balancing Energy Prices by Zone ($/MWh)**

| | Down Balancing | Up Balancing | Total |
|---|---|---|---|
| North Zone 2001 | ($0.06) | $85.51 | $39.62 |
| South Zone 2001 | ($11.10) | $29.59 | $14.29 |
| West Zone 2001 | ($17.14) | $54.21 | $33.46 |
| 2001 (Aug-Dec) | ($9.44) | $58.22 | $22.93 |
| | | | |
| North Zone 2002 | $11.76 | $39.27 | $15.91 |
| South Zone 2002 | $6.03 | $34.72 | $9.17 |
| West Zone 2002 | ($5.19) | $42.43 | $34.13 |
| Houston 2002 | $18.61 | $32.07 | $7.42 |
| 2002 | $11.86 | $36.03 | $12.47 |

The zonal prices are further broken down by zone and by month in Figure 7 and Figure 8. Balancing energy prices would be the same from zone to zone if there were no interzonal transmission congestion.

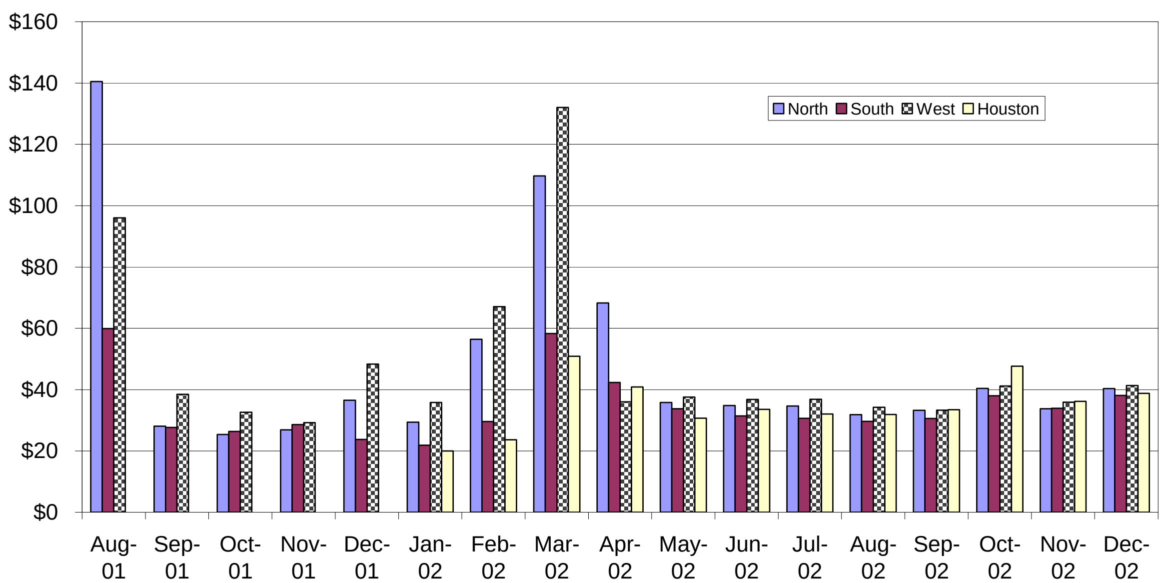
[30] Houston Ship Channel spot prices as reported in Megawatt Daily. Data do not include weekends and holidays.

**Figure 7: Weighted Average Down Balancing Price by Zone ($/MWh)**




In April 2002, Down Balancing prices reached ($998)/MWh in various intervals on seven days in the West and South Zones.

**Figure 8: Weighted Average Up Balancing Price by Zone ($/MWh)**




From May through December 2002, the zonal Up Balancing prices settled within a close range of each other.

### 3. Cost of Balancing Energy

The total cost for balancing energy was $75.7 million in 2001 and $114.2 million in 2002 (Table 9). More than $60 million in balancing energy costs were incurred during the month of August 2001 due to the high levels of zonal congestion that occurred. Under the Protocols in effect at the time, QSEs were not constrained by the impact of their scheduling since the congestion costs were uplifted to the entire market (see Sections III.B, III.D, and IV.A). In 2002, monthly costs for balancing energy ranged from ($4.9 million) to $17.0 million. The average monthly cost was $9.5 million.

**Table 9: Total Cost for Balancing Energy[31]**

| Month | Down Balancing | Up Balancing | Total Cost |
|---|---|---|---|
| **2001 (Aug-Dec)** | ($22,557,555) | $53,162,699 | $75,720,254 |
| **2002** | $53,421,393 | $167,649,329 | $114,227,936 |

[31] Costs are based on ERCOT Operating Day Reports and may not correspond directly to financial settlements. Consistent with those reports, a negative value for Down Balancing in Table 9 represents net payments from ERCOT to QSEs and a positive value for Down Balancing represents net payments from QSEs to ERCOT. Therefore, the Total Cost equals Up Balancing Cost minus Down Balancing Cost.

# III. CONGESTION, TCRS, AND THE TCR AUCTION MARKET

## A. ERCOT Congestion Management Method

ERCOT uses a zonal, portfolio-based model which classifies the region into zones and identifies the commercially significant interfaces between the zones as Commercially Significant Constraints (CSCs). In 2001 there were three zones (South, North, and West) and two CSCs (South-North and West-North); and in 2002 there were four zones (South, North, West, and Houston) and four CSCs (South-North, South-Houston, West-North, North-West). The zones and CSCs are shown in Figure 9 and Figure 10.

Implicit assumptions under the ERCOT zonal model include:

- All generators in a zone have the same shift factors with respect to CSC flowgates
- A generator in one zone does not impact local congestion in other zones (zero shift factor on out of zone lines)

ERCOT solves zonal and local congestion in two steps, in conjunction with a security-constrained dispatch. In the first step, ERCOT clears the predefined CSC congestion, dispatches zonal balancing energy, sets the shadow price of each CSC, and determines the market clearing price for each congestion zone. Balancing Energy Service offers are procured by ERCOT in each zone for zonal load balancing and for inter-zonal congestion relief. The MCPE is determined in each zone based on the portfolio zonal offer curves for balancing energy. If there is no zonal congestion, the MCPE is the same for the entire ERCOT region. In the second step, ERCOT uses resource specific premiums to clear local constraints and to issue resource specific instructions to relieve local congestion, and it uses additional resource specific instructions to rebalance the zonal energy. These resource specific instructions are called "Local Balancing Energy Service." Generators submit resource specific premiums that specify the additional payments (in addition to the zonal MCPE) that they require for the deployment of incremental or decremental balancing energy from the associated, specific resource, if a Market Solution[32] exists. However, more than 90 percent of the time in 2001 and 2002 a Market Solution did not exist. When a Market Solution does not exist, ERCOT issues out-of-merit (OOM) dispatch instructions. Generators who provide OOM services are paid for production costs based on Resource Category Generic Fuel Cost (RCGFC), Resource Category Generic Startup Cost (RCGSC), and Resource Category Generic Operational Cost (RCGOC).[33]

The zonal model is a simplified nodal system with the implicit assumption that local congestion is random and infrequent within zonal boundaries. If local congestion is limited, the zonal model

[32] A Market Solution exists when at least three unaffiliated Resources, with capacity available, submit bids to ERCOT that can solve a circumstance of local congestion and no one bidder is essential to solving the congestion.
[33] The ERCOT Protocols define eight resource categories for generic fuel costs and five resource categories for generic startup costs and generic operational costs.

can work well. If there is substantial local congestion, the simplified assumptions imbedded in the zonal model may break down, and pricing of a large number of transmission constraints may be needed for efficient dispatch and location of new resources.

**Figure 9: ERCOT Zones and CSCs in 2001**

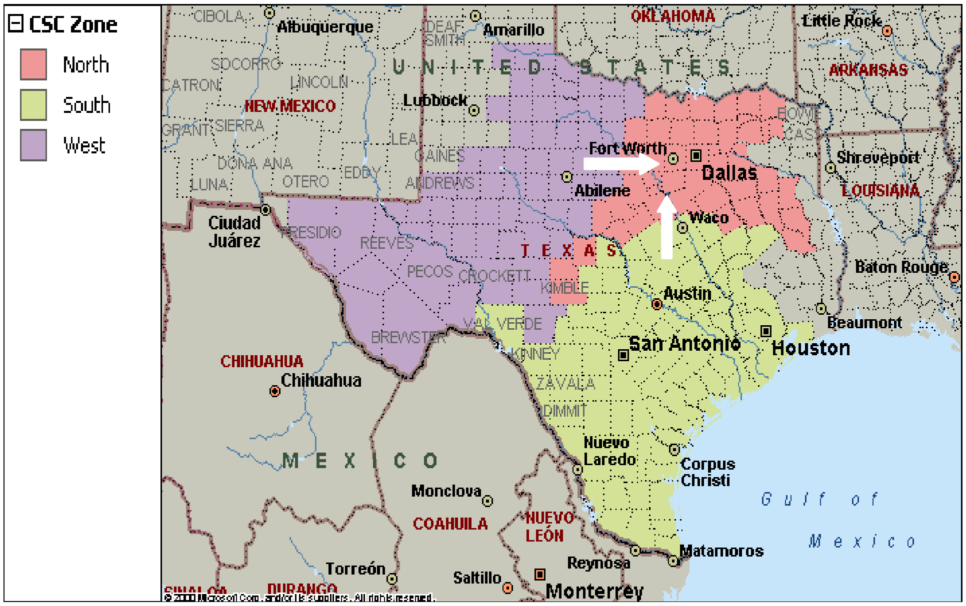
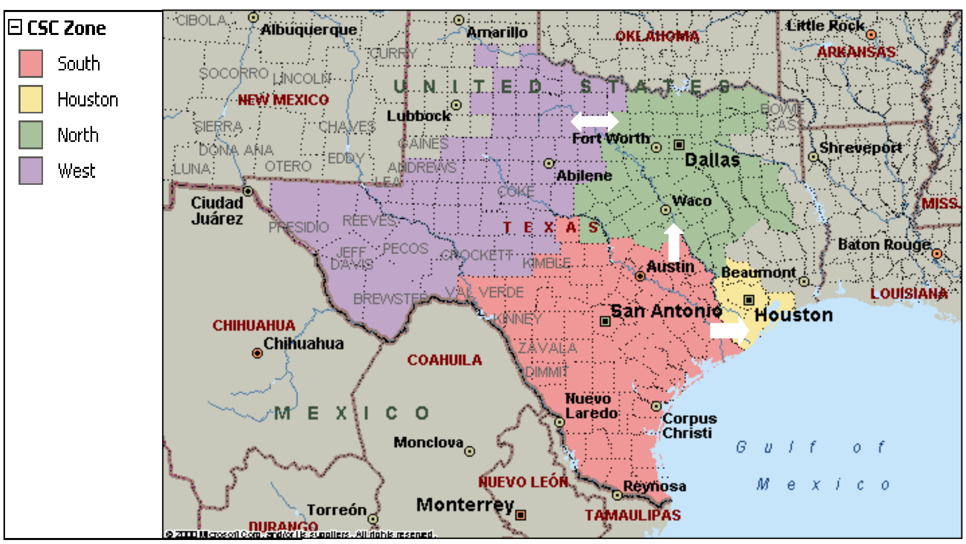



**Figure 10: ERCOT Zones and CSCs in 2002**



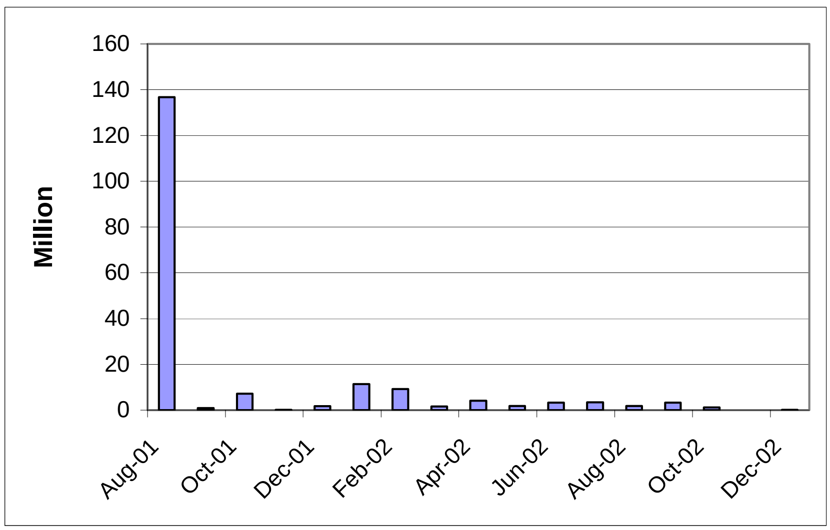

## B. Zonal Congestion Costs

Zonal and local congestion charges have been high but demonstrated different patterns. The total zonal congestion charges for the time period July 31, 2001 through December 31, 2002 were

$187.66[34] million. Payments for load imbalances that occurred in August 2001 resulted in very high charges for the Balancing Energy Neutrality Adjustment (BENA), which were uplifted to all market participants. Over-scheduling of load became an issue since market rules allowed for the socialization of zonal congestion costs of $146.6 million from July 31, 2001 to December 31, 2001. On February 15, 2002, market rules were changed to require the direct assignment of zonal congestion costs, and Transmission Congestion Rights (TCRs) were introduced to allow market participants to hedge their zonal congestion charges. Zonal congestion costs from July 31, 2001 to February 15, 2002 were $165 million while the congestion charges from February 15 to the end of December 2002 were only $22.6 million. Zonal congestion was much lower after February 15, 2002 when direct assignment of zonal congestion rents eliminated the financial incentives for QSE's to overschedule.

**Figure 11: Monthly Zonal Congestion Charge**

| Month | Zonal Congestion Costs (Millions) |
|---|---|
| Aug-01 | $ 136.74 |
| Sep-01 | $ 0.95 |
| Oct-01 | $ 7.10 |
| Nov-01 | $ 0.09 |
| Dec-01 | $ 1.73 |
| Jan-02 | $ 11.34 |
| Feb-02 | $ 9.20 |
| Mar-02 | $ 1.57 |
| Apr-02 | $ 4.05 |
| May-02 | $ 1.80 |
| Jun-02 | $ 3.28 |
| Jul-02 | $ 3.40 |
| Aug-02 | $ 1.80 |
| Sep-02 | $ 3.35 |
| Oct-02 | $ 1.09 |
| Nov-02 | $ 0.03 |
| Dec-02 | $ 0.15 |
| Total | $ 187.66 |



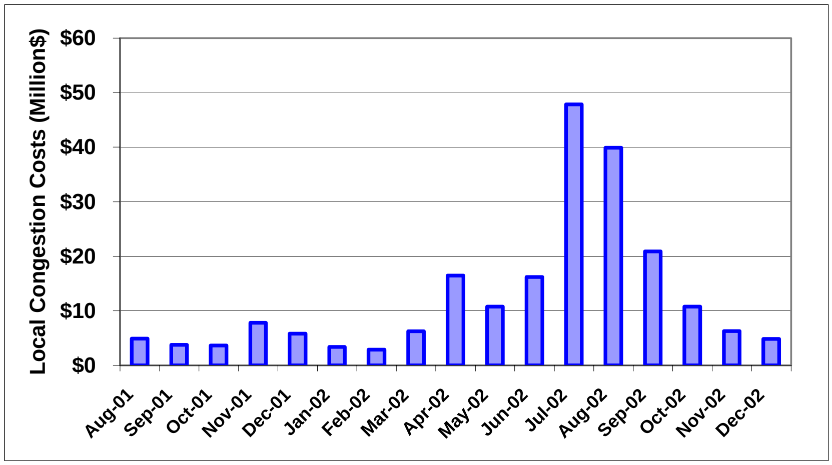

## C. Local Congestion Costs

Local congestion costs were about $212 million from July 31, 2001 to December 31, 2002, including $25.9 million in 2001 and $186.3 million in 2002 (Figure 12). OOME Down costs continue to be socialized, making it possible for market participants that own generation on the constrained side of a local constraint to game the market by using the DEC game. The DEC game occurs when (1) a market participant submits a schedule that if followed would cause congestion; (2) the market participant is paid to "solve" the anticipated congestion by generating less than what was scheduled; and (3) the cost of these local congestion payments are socialized. If participants are not charged for creating congestion when they schedule too much flow over a constrained local line, then they have an incentive to schedule as much output as possible in order to collect payments to generate below scheduled output.

[34] Zonal congestion costs based on generation schedule and load schedule.

**Figure 12: Local Congestion Costs**

| Month | Local Congestion Costs (Million$) |
|---|---|
| Aug-01 | $4.89 |
| Sep-01 | $3.77 |
| Oct-01 | $3.63 |
| Nov-01 | $7.78 |
| Dec-01 | $5.81 |
| Jan-02 | $3.36 |
| Feb-02 | $2.86 |
| Mar-02 | $6.26 |
| Apr-02 | $16.43 |
| May-02 | $10.76 |
| Jun-02 | $16.17 |
| Jul-02 | $47.85 |
| Aug-02 | $39.90 |
| Sep-02 | $20.86 |
| Oct-02 | $10.74 |
| Nov-02 | $6.27 |
| Dec-02 | $4.84 |
| Total | $212.19 |




The $212.19 million amount for local congestion can be divided into the following subcategories:

| | |
|---|---|
| OOM Capacity (OOMC)[35] | $88.85 million |
| OOM Energy Up (OOME Up) | $37.22 million |
| OOM Energy Down (OOME Down) | $39.43 million |
| Resource Specific Up (instruction)[36] | $23.33 million |
| Resource Specific Down (instruction) | $23.37 million |
| | $212.19 million |

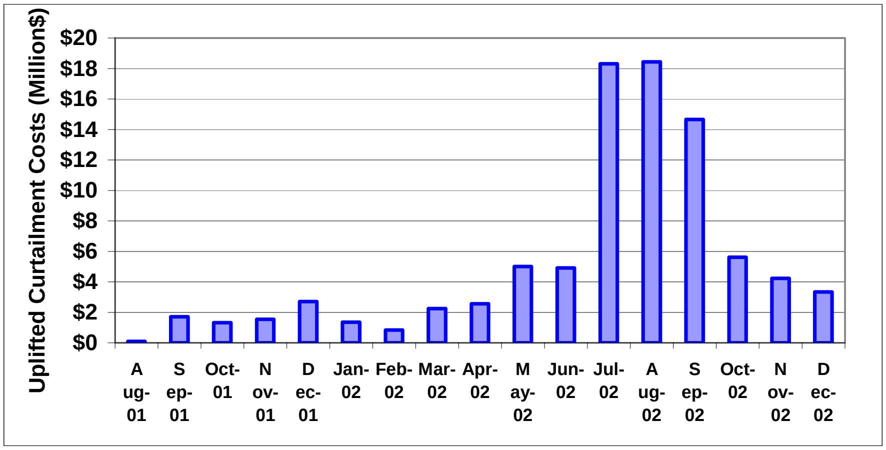
OOME Up and Down consists of payments to QSEs for (1) manual out-of-merit instructions by operators or (2) deployment instructions generated in Step 2 of congestion clearing when there is no Market Solution. Resource Specific Up and Down costs are payment to QSEs for Local Balancing Energy when there is a Market Solution.

[35] The local congestion costs for capacity does not include the Frontera Alternative Dispute Resolution (ADR) which paid Frontera $18.7 million for OOMC provided during the time period April 2002 through September 2002. The $18.7 million amount was assessed separately to QSEs representing load.

[36] The total cost for Resource Specific Up and Down was estimated to be $46.7 million. Due to a system error that was corrected, this amount was expected to decline substantially when ERCOT resettles certain local congestion-related payments.

**Figure 13: Local Congestion Cost for Capacity**

| Month | OOMC Cost (Million$) |
|---|---|
| Aug-01 | $0.09 |
| Sep-01 | $1.72 |
| Oct-01 | $1.31 |
| Nov-01 | $1.54 |
| Dec-01 | $2.71 |
| Jan-02 | $1.35 |
| Feb-02 | $0.84 |
| Mar-02 | $2.25 |
| Apr-02 | $2.56 |
| May-02 | $5.01 |
| Jun-02 | $4.91 |
| Jul-02 | $18.32 |
| Aug-02 | $18.43 |
| Sep-02 | $14.65 |
| Oct-02 | $5.61 |
| Nov-02 | $4.23 |
| Dec-02 | $3.34 |
| Total | $88.85 |




The local congestion costs for capacity and energy by month are shown in Figure 13 and Figure 14, respectively. Figure 14 combines local congestion cost for energy for both OOME and Resource Specific instruction as well as the costs of Category 4 instructions.

**Figure 14: Local Congestion Cost for Energy**

| Month | Local Congestion Costs for Energy (Million$) |
|---|---|
| Aug-01 | $4.81 |
| Sep-01 | $2.05 |
| Oct-01 | $2.31 |
| Nov-01 | $6.25 |
| Dec-01 | $3.10 |
| Jan-02 | $2.02 |
| Feb-02 | $2.03 |
| Mar-02 | $4.01 |
| Apr-02 | $13.87 |
| May-02 | $5.75 |
| Jun-02 | $11.26 |
| Jul-02 | $29.53 |
| Aug-02 | $21.47 |
| Sep-02 | $6.21 |
| Oct-02 | $5.13 |
| Nov-02 | $2.04 |
| Dec-02 | $1.51 |
| Total | $123.35 |

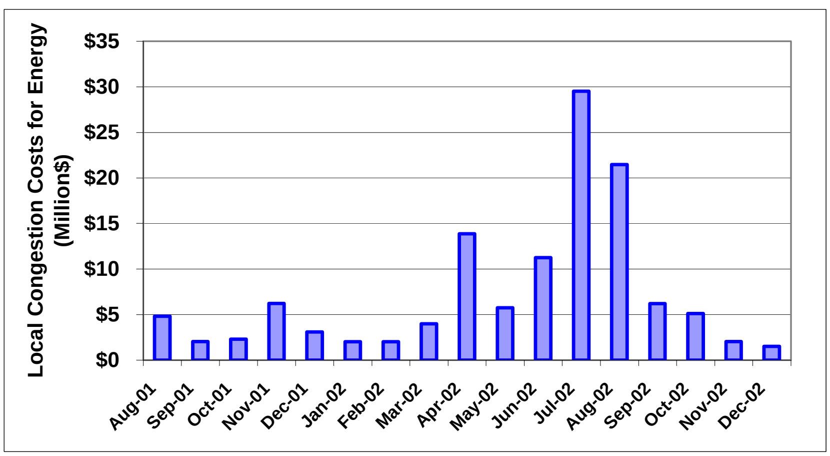
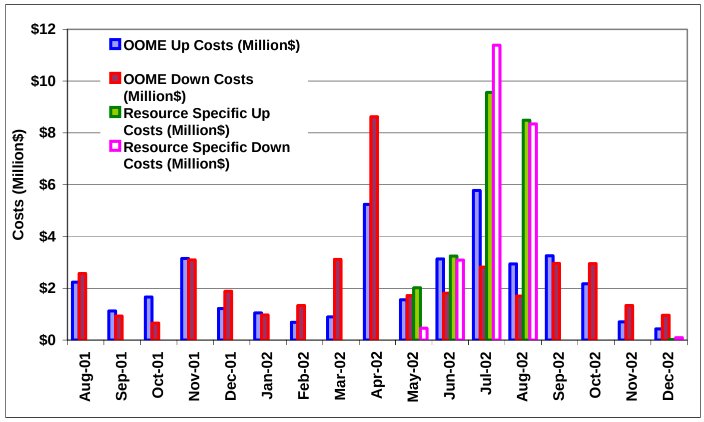



Figure 15 summarizes monthly local congestion costs by different categories.

**Figure 15: Local Congestion Cost for Energy in Detail**

| Month | OOME Up Costs (Million$) | OOME Down Costs (Million$) | Resource Specific Up Costs (Million$) | Resource Specific Down Costs (Million$) |
|---|---|---|---|---|
| Aug-01 | $2.23 | $2.57 | $0.00 | $0.00 |
| Sep-01 | $1.12 | $0.93 | $0.00 | $0.00 |
| Oct-01 | $1.66 | $0.66 | $0.00 | $0.00 |
| Nov-01 | $3.16 | $3.09 | $0.00 | $0.00 |
| Dec-01 | $1.22 | $1.88 | $0.00 | $0.00 |
| Jan-02 | $1.05 | $0.97 | $0.00 | $0.00 |
| Feb-02 | $0.69 | $1.34 | $0.00 | $0.00 |
| Mar-02 | $0.90 | $3.11 | $0.00 | $0.00 |
| Apr-02 | $5.24 | $8.63 | $0.00 | $0.00 |
| May-02 | $1.55 | $1.72 | $2.02 | $0.45 |
| Jun-02 | $3.13 | $1.80 | $3.24 | $3.09 |
| Jul-02 | $5.77 | $2.82 | $9.56 | $11.38 |
| Aug-02 | $2.94 | $1.70 | $8.49 | $8.35 |
| Sep-02 | $3.25 | $2.96 | $0.00 | $0.00 |
| Oct-02 | $2.18 | $2.95 | $0.00 | $0.00 |
| Nov-02 | $0.70 | $1.34 | $0.00 | $0.00 |
| Dec-02 | $0.43 | $0.96 | $0.02 | $0.10 |
| Total | $37.22 | $39.43 | $23.33 | $23.37 |




Local congestion consistently occurs in several specific locations, but with different patterns in 2001 (Figure 16) and 2002 (Figure 17). For example, in 2001 the DFW Area was the eighth highest local congestion cost area and accounted for only 3.5% of the costs, but in 2002 it was ranked number one and accounted for 27.6% of the costs. Similarly, the North Area was ranked number six in 2001 and accounted for 5.9% of local congestion costs, but in 2002 it was ranked number two and accounted for 16.7% of costs. The Wind Area, which is an area of concentrated wind generation near McCamey, Texas, also experienced a significant increase in local congestion in 2002. Currently, market participants are discussing a plan that would reduce the congestion uplift generated by the wind resources by eliminating almost all OOME down payments and issuing tradable physical transmission rights on a resource share basis behind the constraint. The congestion costs in Corpus Christi, Laredo, and Valley area may be impacted the Reliability-Must-Run (RMR) contracts.

**Figure 16: 2001 Local Congestion Costs by Area**

| Area | Local Congestion |
|---|---|
| West | 5.81 |
| Valley | 4.95 |
| Corpus | 4.68 |
| Houston | 2.93 |
| Laredo | 2.27 |
| North | 1.57 |
| South | 1.44 |
| DFW | 0.94 |
| San Antonio | 0.76 |
| Austin | 0.74 |
| Wind | 0.51 |
| Total | 26.61 |

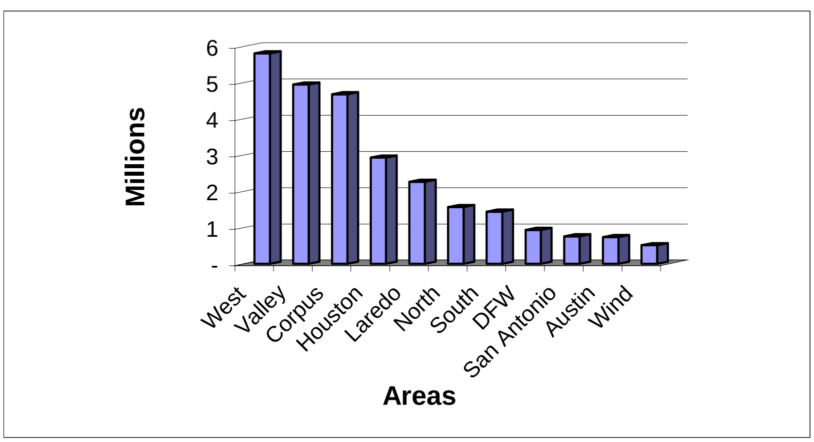
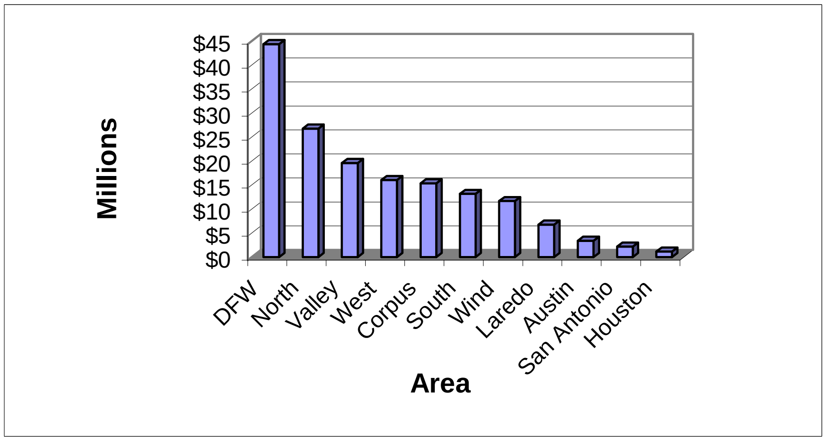


**Figure 17: 2002 Local Congestion Costs by Area**

| Area | Local Congestion |
|---|---|
| DFW | $44.37 |
| North | $26.78 |
| Valley | $19.61 |
| West | $16.04 |
| Corpus | $15.37 |
| South | $13.16 |
| Wind | $11.67 |
| Laredo | $6.76 |
| Austin | $3.39 |
| San Antonio | $2.16 |
| Houston | $1.17 |
| Total | $160.49 |




## D. ERCOT Uplift

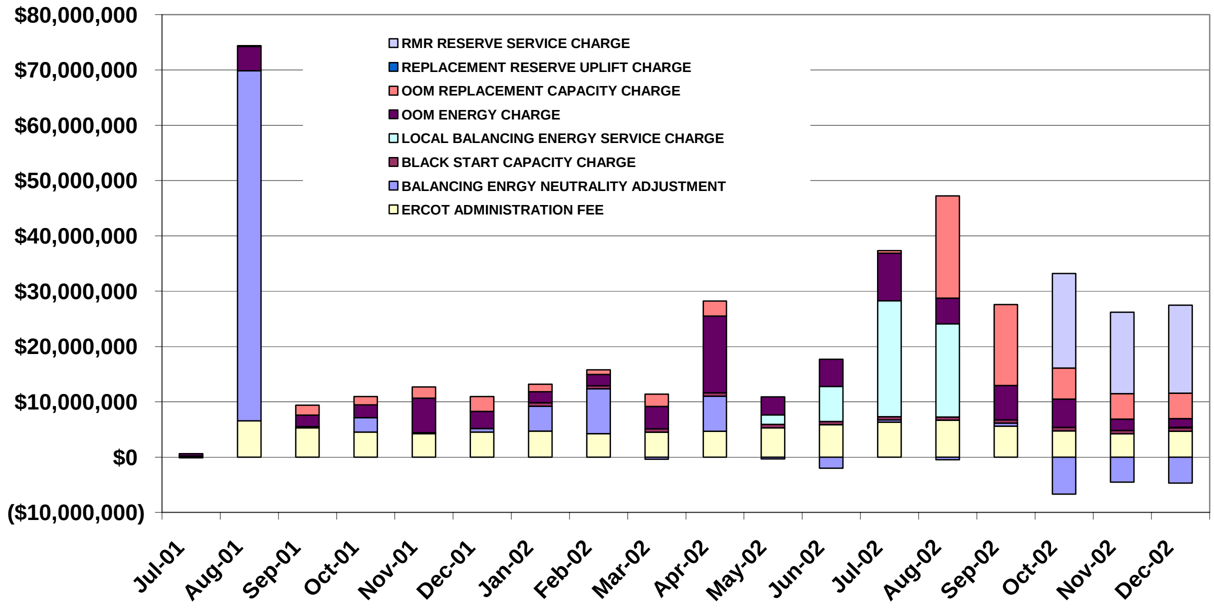
Uplift is the process of allocating costs to QSEs based on loads and exports within the ERCOT region. The total uplift in 2001 was $118.8 million, and in 2002 it was $277.2 million. These figures include ERCOT Administrative Fees of $25.4 million in 2001 and $61.5 million in 2002. The uplift consists of mainly local congestion related costs such as Local Balancing Energy Service Charge (Category 4), OOMC and OOME costs, and RMR contracts.

**Table 10: ERCOT Administration Fee and Uplift Costs**

| Month | ERCOT ADMIN FEE | BALANCING ENRGY NEUTRALITY ADJUSTMENT | BLACK START CAPACITY CHARGE | LOCAL BALANCING ENERGY SERVICE CHARGE | OOM ENERGY CHARGE | OOM REPLACEMENT CAPACITY CHARGE | REPLACEMENT RESERVE UPLIFT CHARGE | RMR RESERVE SERVICE CHARGE | Total |
|---|---|---|---|---|---|---|---|---|---|
| Jul-01 | $ 229,205 | $ (146,046) | - | - | $ 398,983 | - | - | - | $ 482,142 |
| Aug-01 | $ 6,566,363 | $ 63,293,414 | - | - | $ 4,407,605 | $ 86,591 | $ 7,206 | - | $ 74,361,179 |
| Sep-01 | $ 5,278,208 | $ 256,392 | - | - | $ 2,051,896 | $ 1,802,389 | - | - | $ 9,388,884 |
| Oct-01 | $ 4,526,921 | $ 2,630,931 | - | - | $ 2,313,647 | $ 1,485,032 | - | - | $ 10,956,531 |
| Nov-01 | $ 4,262,083 | $ 160,880 | - | - | $ 6,247,669 | $ 2,003,850 | - | - | $ 12,674,482 |
| Dec-01 | $ 4,528,600 | $ 624,938 | - | - | $ 3,096,790 | $ 2,710,868 | - | - | $ 10,961,195 |
| Jan-02 | $ 4,714,204 | $ 4,490,799 | $ 616,828 | - | $ 2,019,361 | $ 1,345,463 | - | - | $ 13,186,655 |
| Feb-02 | $ 4,248,696 | $ 8,098,418 | $ 557,135 | - | $ 2,025,143 | $ 836,514 | - | - | $ 15,765,906 |
| Mar-02 | $ 4,490,335 | $ (387,765) | $ 616,829 | - | $ 4,045,236 | $ 2,245,948 | - | - | $ 11,010,582 |
| Apr-02 | $ 4,681,842 | $ 6,352,883 | $ 596,101 | - | $ 13,870,571 | $ 2,722,634 | - | - | $ 28,224,031 |
| May-02 | $ 5,281,266 | $ (304,235) | $ 616,828 | $ 1,736,873 | $ 3,275,150 | - | - | - | $ 10,605,882 |
| Jun-02 | $ 5,849,346 | $ (2,009,412) | $ 596,930 | $ 6,328,364 | $ 4,934,370 | - | - | - | $ 15,699,599 |
| Jul-02 | $ 6,323,287 | $ 414,970 | $ 586,601 | $ 20,943,252 | $ 8,589,643 | $ 497,973 | - | - | $ 37,355,725 |
| Aug-02 | $ 6,657,998 | $ (456,021) | $ 601,665 | $ 16,832,670 | $ 4,641,022 | $ 18,514,264 | - | - | $ 46,791,597 |
| Sep-02 | $ 5,624,945 | $ 519,071 | $ 592,244 | $ - | $ 6,211,711 | $ 14,649,956 | - | - | $ 27,597,927 |
| Oct-02 | $ 4,752,112 | $ (6,683,587) | $ 617,225 | $ - | $ 5,130,228 | $ 5,606,320 | - | $ 17,100,961 | $ 26,523,258 |
| Nov-02 | $ 4,239,792 | $ (4,523,539) | $ 587,753 | $ - | $ 2,039,792 | $ 4,622,409 | - | $ 14,733,906 | $ 21,700,114 |
| Dec-02 | $ 4,682,990 | $ (4,710,083) | $ 605,743 | $ 116,804 | $ 1,545,486 | $ 4,620,579 | - | $ 15,910,038 | $ 22,771,558 |
| **Total** | **$ 86,938,192** | **$ 67,622,007** | **$ 7,191,881** | **$ 45,957,964** | **$ 76,844,302** | **$ 63,750,791** | **$ 7,206** | **$ 47,744,905** | **$ 396,057,248** |

In August 2001, ERCOT experienced very high uplift charges for BENA. After direct assignment of zonal congestion was initiated in February 2002, BENA charges were reduced substantially. On the other hand, the Local Balancing Energy Service Charge (Category 4), OOMC costs, and OOME costs increased significantly in late 2002.

**Figure 18: ERCOT Administration Fee and Uplift Costs**




## E. Congestion Rights

Transmission Congestion Rights and Pre-assigned Congestion Rights (PCRs) function as financial hedges (similar to financial options with zero strike prices) against the zonal congestion charges.[37] Congestion charges are imposed on QSEs based on the flow that their scheduled inter-zonal transactions induce on the CSCs. The total costs of zonal congestion comprise those portions of RPRS costs and the Balancing Energy Service costs associated with managing zonal congestion. The TCR and PCR holder receives an amount equal to the directly assigned congestion charges for an equivalent quantity of scheduled flow. Neither TCRs nor PCRs are deratable.

Sixty percent of the total annual quantity of TCRs less PCRs for any given CSC are awarded to market participants based on the results of an annual auction. These TCRs are made available in the annual auction for each hour of the year. The amount of TCRs auctioned in the monthly auction is the total monthly quantity of TCRs, less any PCRs, and less any TCRs for that month sold in the annual auction. To avoid the compounding of market power that could result from joint ownership of generation and transmission rights, QSEs are prohibited from holding more than 25%[38] of the TCRs on any constrained corridor. For the annual and monthly auction, the quantity of TCRs used to calculate the 25% limit is based on the total annual and monthly

[37] Zonal congestion charges are based on the shadow price of a CSC. The shadow price is equal to the marginal cost of solving the last megawatt of congestion on a constraint that is based upon the balancing energy prices on each side of the constraint and the relative impact on the congested line of the generation resources deployed.

[38] The 25% limitation was imposed to mitigate market power since a generator with market power (i.e., substantial ownership of installed generation) in an importing zone will have an additional incentive to withhold capacity and raise prices in that zone if the generator holds a substantial amount of TCRs since it can then also benefit from the appreciation of TCR values.

quantity of TCRs (which includes PCRs). Each annual auction is completed no later than the 15th of December, on a date set by ERCOT. Market participants can exchange TCRs and PCRs in any secondary market. ERCOT has a database of hourly TCR holders with the annual and monthly first-purchasers of TCRs and hourly PCR holders.

The TCRs are defined as financial rights in one megawatt denominations for specific CSCs. A TCR entitles its holder to receive a payment equal to the shadow price on the corresponding CSC. The TCRs are issued by ERCOT in amounts that match the available transmission capacity of the constrained corridors. TCRs can be divided into smaller time segments and traded among market participants in secondary markets. About 20 percent of the available rights are assigned as PCRs at reduced prices to municipally-owned utilities and electric cooperatives that have grandfathered rights to the transmission system. Starting in 2003, PCR holders must pay 15% of the auction price of the TCR auctioned on the same CSC as the PCR. The revenue from the TCR auction is distributed to the load, whereas congestion revenues cover payment to TCR holders. PCRs are tradable starting in 2003.

TCRs were implemented in ERCOT along with the implementation of the direct assignment of zonal congestion charges on February 15, 2002. Stakeholders wanted the TCR Program to become effective when direct assignment of zonal congestion costs began so they could hedge their zonal congestion costs. ERCOT instituted a simultaneous combinatorial auction[39] for TCRs on December 2002.

## F. TCR Auction Results[40]

The total TCR auction revenue was $91.1 million from February 15, 2002 to December 31, 2002; and the total TCR credit payments were $22.5 million. Thus, TCR auction revenues exceeded credit payments by about $68.7 million during 2002.

[39] A simultaneous combinatorial auction structure was required by the Commission in Docket No 23220. The awards can be determined by a simultaneous optimization that selects the winning bids so as to maximize revealed social value.

[40] Most of this section is based on “TCR Program Report, July 1 through December 31, 2002”, March 14, 2002, Revised. The report is available on the ERCOT website at: https://tcr.ercot.com/default.cfm?func=tcrpostings

**Table 11: TCR Auction Revenues**

| 2002 Auction | Total Revenues | Commercially Significant Constraint | | | |
|---|---|---|---|---|---|
| | | **West-North** | **South-North** | **South-Houston** | **North-West** |
| Annual | $69,620,018 | $9,027,612 | $32,713,554 | $27,878,852 | N/A |
| February | $879,544 | $102,648 | $424,072 | $349,104 | $3,720 |
| March | $1,199,745 | $144,634 | $452,315 | $592,7967 | $9,999 |
| April | $992,637 | N/A | $481,888 | $510,749 | N/A |
| May | $2,725,108 | $373,309 | $1,429,417 | $849,469 | $72,912 |
| June | $5,750,813 | $925,200 | $2,944,800 | $1,872,000 | $8,813 |
| July | $4,539,308 | $603,310 | $1,397,678 | $2,530,344 | $7,976 |
| August | $3,021,972 | $199,050 | $1,395,000 | $1,417,878 | $10,044 |
| September | $754,848 | $89,640 | $321,840 | $343,368 | N/A |
| October | $552,999 | N/A | $140,805 | $412,194 | N/A |
| November | 818,892 | $84,859 | $270,000 | $426,773 | $37,260 |
| December | 219,621 | $17,975 | $69,006 | $122,016 | $10,624 |
| **Total** | $91,075,504 | $11,568,237 | $42,040,376 | $37,305,544 | $161,348 |

Analysis of the TCR Program data from February 15, 2002 through December 31, 2002 indicates the following:

- Number of TCRs Sold
  - The number of TCRs sold during 2002 was 4,401 on S-H, 2,836 on S-N, 2,368 W-N, and 699 on N-W. There were more TCRs sold during June on the S-N than was sold during the annual auction due to a significant increase in capacity on the S-N CSC.

- TCR Auction Revenues
  - The annual auction produced more than 76% of the total TCR auction revenues for 2002. June and July had the highest monthly revenues, producing 6.3% and 4.9% of the total TCR auction revenues for 2002.
  - The S-N and S-H CSCs produced the largest auction revenues during the year (about $42 and $37 million, respectively).

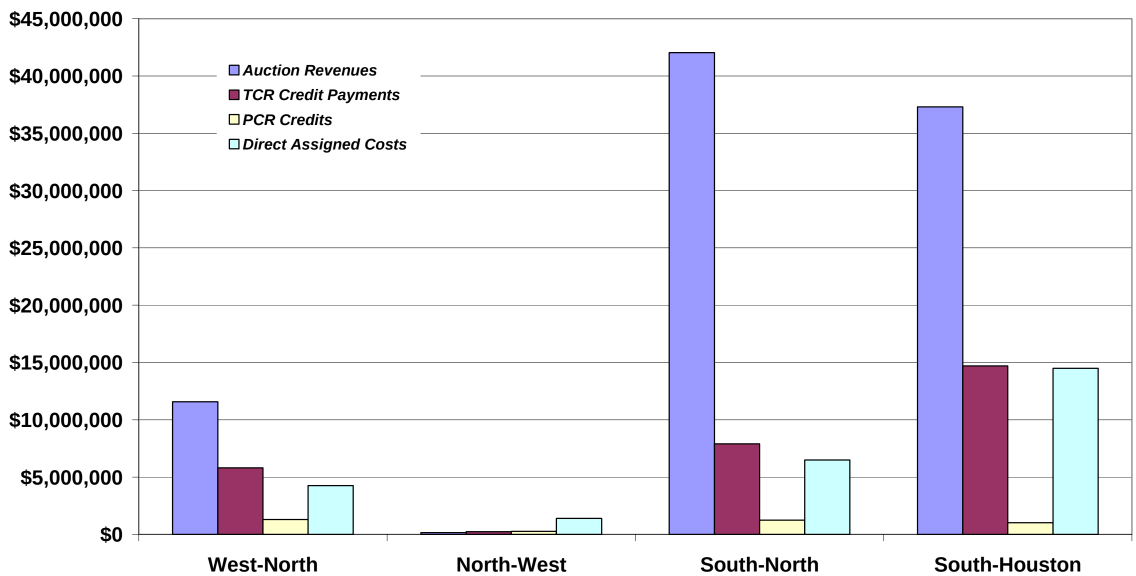
- TCR Clearing Prices and CSC Shadow Prices
  - CSC clearing prices markedly decreased after July 2002.
  - CSC shadow prices were extremely volatile throughout the year.

- TCR Auction Revenues Exceeded TCR Credit Payments
  - TCR owners placed a high value on perceived risk of zonal congestion costs.
  - TCR auction revenues exceeded credit payments by about $68.7 million during 2002.
  - There were eight instances where TCR credit payments exceeded auction revenues mostly between the West and North Zones.

- TCR Clearing Prices (costs) Exceeded TCR Credit Payments
  - TCRs provided poor rates of return for owners. The average CSC shadow price exceeded the TCR clearing price on only 10 occasions.

- TCR Auction Revenues exceed Total Direct Assigned Rents
  - Auction revenues exceeded direct assigned rents by more than $70.6 million.
    - S-N: $42 million
    - S-H: $37.5 million
    - W-N: $11.5 million
    - N-W: $161,000

**Figure 19: Comparison of TCR Revenues, TCR Credit Payments, PCR Credits, and Direct Assigned Costs**




The TCR revenues only exceeded TCR credits in the North-West CSC and then by only $240,000 in 2002. TCRs were over valued when compared to the actual financial risk of congestion. Since TCR auction revenues exceeded TCR credit payments by more than $62 million. Direct assignment costs were $26.6 million while total PCR credits totaled around $3.8 million.

Figure 20 and Figure 21 compare the price of TCRs (weighted market clearing price) to the value of TCRs (shadow price). The weighted market clearing price was calculated by considering the quantity of TCRs and the TCR clearing prices for both the annual and monthly clearing prices. The S-N CSC produced the highest monthly average shadow price[41] in September ($6.79). Total CSC shadow prices for 2002 were:

- S-H: $29.25
- S-N: $23.37
- W-N: $18.98
- N-W: $8.40

[41] Shadow price is the cost of an operation to affect a one (1) MW change in a constraint.

**Figure 20: Weighted Clearing Prices and CSC Shadow Prices (February – June)**

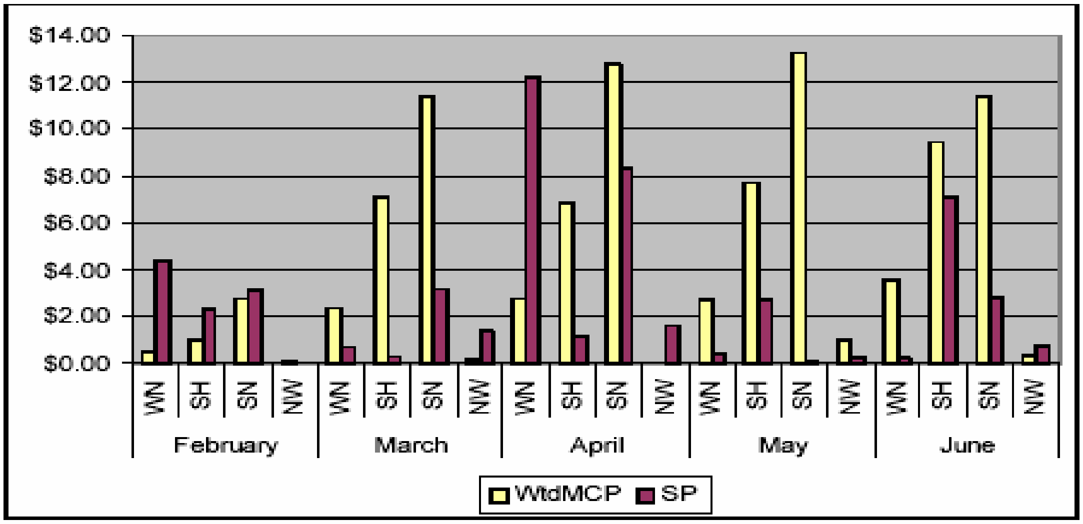
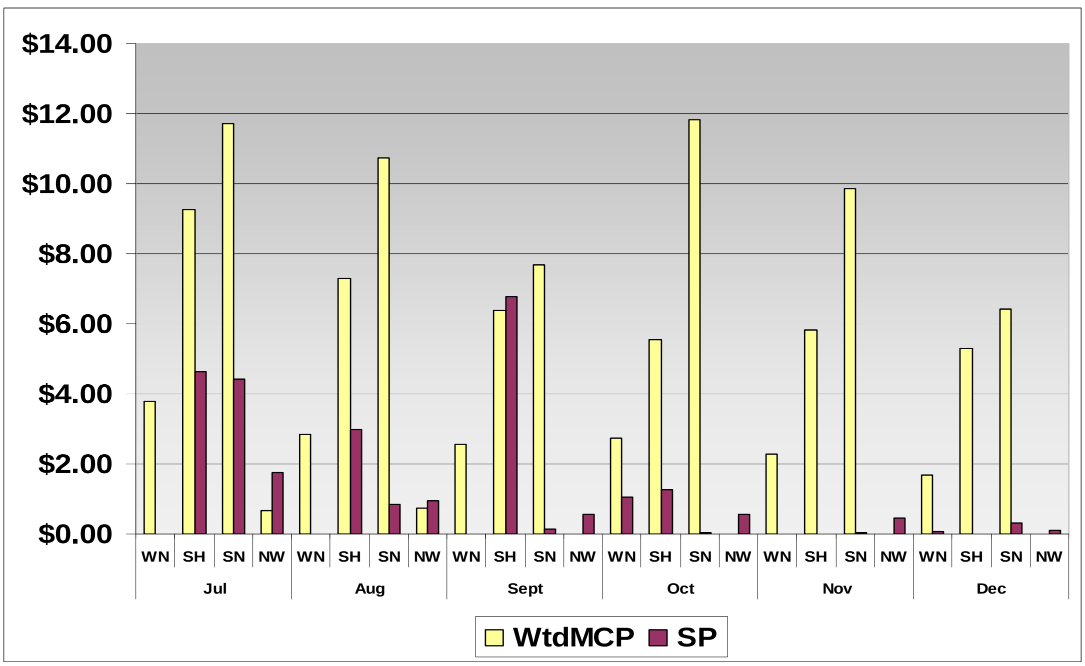



**Figure 21: Weighted Clearing Prices and CSC Shadow Prices (July-December)**




Municipal and co-op utilities which own or have a long-term (greater than five years) contractual commitment for annual capacity and energy from a specific remote generation resource and that commitment were entered into prior to September 1, 1999, are eligible for PCRs. PCRs are priced differently than TCRs, and they are allocated rather than awarded as a result of the annual TCR auction process. The eligibility, pricing and annual allocation of PCRs are addressed in Protocol Section 7.5.6. For all other purposes, PCRs are functionally and financially equivalent to TCRs. PCR holders will be issued invoices that are based on 15 percent of the TCR clearing price from the annual auction. Payment of these invoices is required prior to the distribution of PCRs. PCRs count for about 25% of available transmission capacity on predefined CSCs.

Figure 22 and Figure 23 show the number of PCRs scheduled and unscheduled by CSC, by month. PCRs had the use-it-or-lose-it feature (unscheduled PCRs therefore reduced PCR credit payments), but this was changed in 2003.

**Figure 22: PCRs Scheduled and Unscheduled (February – June)**

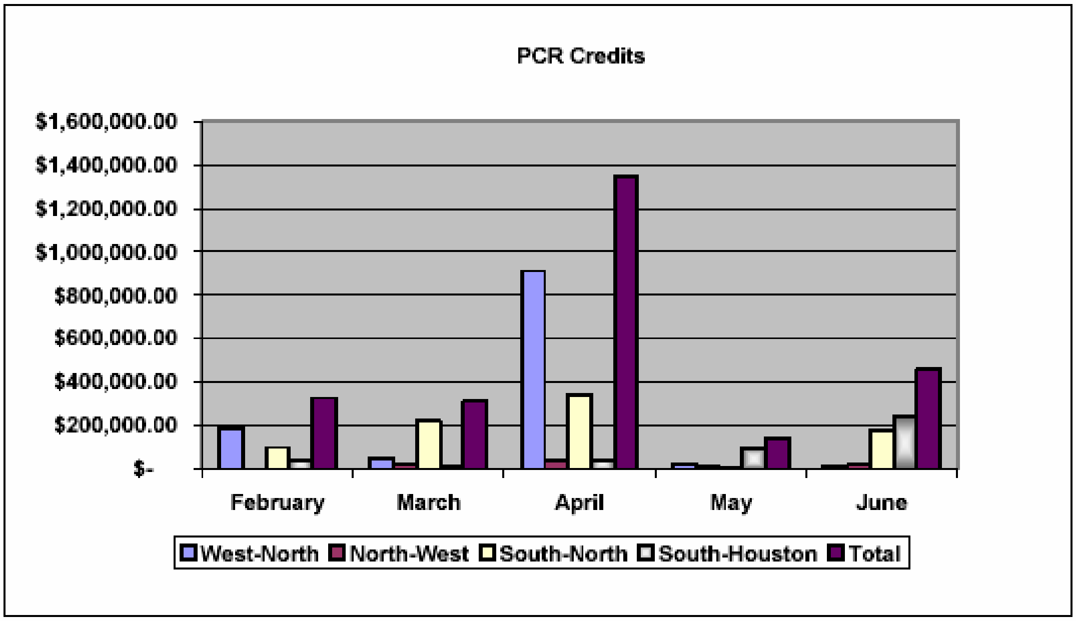
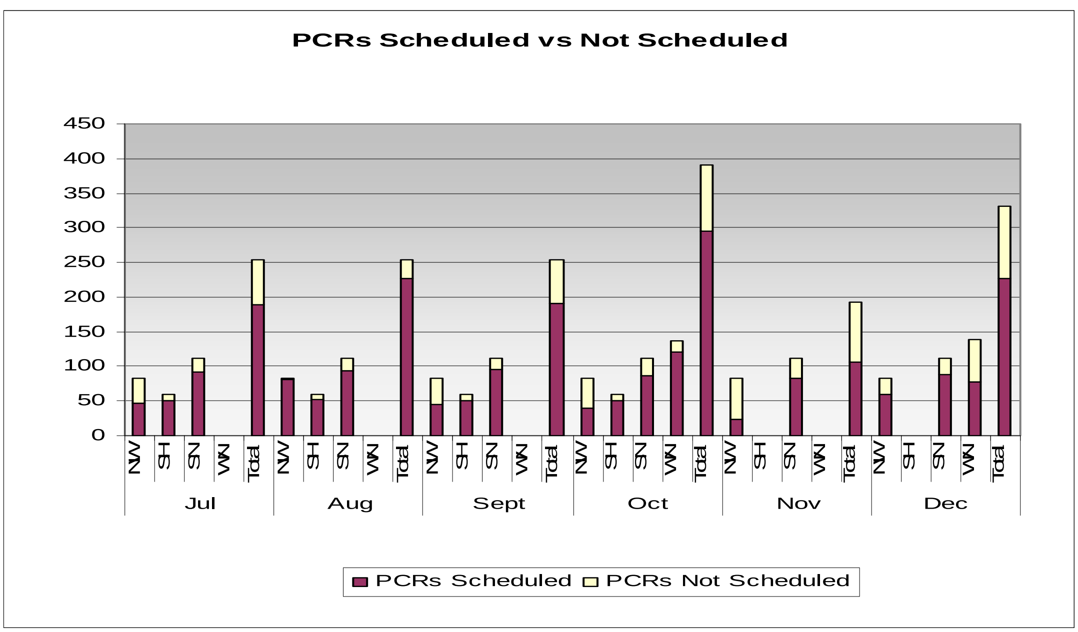



**Figure 23: PCRs Scheduled and Unscheduled (July – December)**



# IV. MARKET ISSUES

## A. Overscheduling and BENA

When ERCOT began operation as a single control area on July 31, 2001, the costs for relieving zonal congestion were "uplifted" or spread among market participants on the basis of the market participant's share of the load on the system. This mechanism divorced the costs of relieving congestion from those parties that actually caused the congestion, and provided incentives for market participants to schedule generation across congested CSCs, knowing that they would likely receive more in payments to relieve that congestion than they would be assessed. The Commission required ERCOT to switch to a direct assignment methodology by the earlier of January 1, 2003 or six months after zonal congestion costs exceeded $20 million. It also required ERCOT to implement a system of Transmission Congestion Rights, which would allow market participants to hedge their anticipated congestion costs. The $20 million threshold was reached on August 15, 2001, and direct assignment of zonal congestion and the TCR system were implemented on February 15, 2002. Once direct assignment was implemented, market participants had to exercise greater caution in scheduling across CSCs, and zonal congestion costs were reduced significantly. Interzonal congestion costs totaled $165,090,992 from July 31, 2001 through February 14, 2002. After direct assignment was implemented on February 15, 2002, additional zonal congestion costs totaled only $22,565,694 through the end of the year.

Significant transmission congestion occurred in ERCOT during August 2001, primarily caused by market participants scheduling power from the southern part of the state to the northern part of the state. This was not unexpected since much of the new, low-cost generation has been constructed in southern area of the state, and congestion typically occurs during the summer months when demand for electricity is the highest. However, the manner in which market participants scheduled their loads and resources became an issue. In accordance with the Protocols, ERCOT relieved the congestion by deploying balancing energy, and it aggregated the zonal congestion costs (as well as other costs related to load imbalance, resource imbalance, and uninstructed deviation) in the Balancing Energy Neutrality Adjustment. BENA charges were then allocated to market participants on the basis of their load. BENA charges for August alone were approximately $75.9 million.

Market participants had little incentive to schedule power in a manner that avoided creating transmission congestion because they would be allocated less in the way of BENA than they could receive as payments to relieve congestion. Additionally, if a market participant scheduled power for load that did not exist, they would receive payments from ERCOT (called "load imbalance payments"). Due to the high level of the BENA charges and this potential for gaming, concerns were raised by some market participants that BENA charges had been inflated by some market participants through intentionally overscheduling their loads. Other market participants argued that overscheduling was not intentional and was attributable to normal forecasting errors, new market rules, delayed switching, and other transitional problems in the new market.

The Commission Staff investigated the scheduling behaviors of market participants and found that a number of QSEs had scheduled load with ERCOT that dramatically exceeded their actual load. While scheduling in this manner did not appear to have contributed to high power prices, it allowed these companies to increase their revenues in the ERCOT settlement process, at the expense of other market participants.

In particular, Commission Staff found that six QSEs (AEP, Enron, Constellation, Mirant, Reliant, and TXU) received more than $2 million each in load imbalance revenues for the month of August. Commission Staff held several meetings and public workshops with the QSEs to assess the reasons for their overscheduling. Ultimately, the Commission Staff and five of the six QSEs entered into settlements that included an agreement that attributed overscheduling to market transition issues, including incomplete and inaccurate data in the marketplace and start-up errors. The settlement resulted in refunds of $10,478,999 to other QSEs[42] that had been assessed BENA charges caused by the overscheduling.[43] The settlements were approved by the Commission in November 2002.[44] Commission Staff reached a settlement with the sixth QSE, Enron, in March 2003. The settlement provides that upon entry of an order by the Bankruptcy Court, Enron agrees to pay a penalty of $6,500,000 to the Texas Comptroller of Public Accounts and a remittance of load imbalance payments in the amount of $2,900,000 to ERCOT to be refunded to other QSEs. The Commission approved the settlement in May 2003.[45]

These overscheduling issues should not recur in the future because the change to direct assignment of zonal congestion costs removed incentives for QSEs to overschedule load. This change significantly reduced the total amount of congestion that occurs.

## B. Potential for Gaming in ERCOT

### 1. Enron Strategies and Wash Trades

Disclosure of the trading strategies used by Enron in California heightened the awareness of Texas regulators as to whether market rules could be exploited by generators, power marketers, or other wholesale market participants seeking to achieve exorbitant profits in the state's newly restructured electric market. The Market Oversight Division analyzed Enron's trading strategies and concluded that for the most part they could not be used in ERCOT because they were specific to California's market rules and the configuration of its electric grid. In addition, the potential magnitude of exposure to California type problems would be significantly less in ERCOT due to the primarily bilateral nature of the market and the opportunity that market participants have to self-supply ancillary services. Also, the ERCOT market rules were developed with the benefit of lessons learned from California and other electricity markets so

[42] In accordance with terms of the settlement, refunds were made to QSEs other than TXU.

[43] During settlement discussions it was determined that Constellation's scheduling activities did not harm the market so Constellation was not required to make refunds.

[44] *PUC Investigation into Overscheduling in ERCOT in August 2001*, Docket No. 25755, November 11, 2002.

[45] *Notice of Intent to Assess an Administrative Penalty Against Enron Power Marketing, Inc., and Request for Regulatory Findings Pertaining to Future Fitness of EPMI, its Officers and Directors for Certification in the ERCOT Market Based on Alleged Violations of Texas Utilities Code §39.151(d), (i), and (j); PUC Substantive Rules 25.200(b) and 25.361; and Order on Rehearing in P.U.C. Docket No. 23220, Pursuant to P.U.C. Procedural Rule 22.246, Administrative Penalties*, Docket No. 25968, May 29, 2003.

they include strong safeguards against many of the mistakes made elsewhere. MOD presented its conclusions concerning the Enron strategies to the Legislative Oversight Committee (LOC) in June 2002. A summary of MOD's analysis appears in Table 12.

Although the Enron strategies could not be directly transferred to ERCOT, the Commission directed the Staff to issue an information request to market participants to determine whether they had engaged in any of the Enron strategies, or variants thereof, and whether they had engaged in any contemporaneous purchase/sale transactions including "Wash," "Round Trip," "Bragawatt," or "Sell/Buyback" trades. On June 12, 2002 Staff issued a set of information requests to QSEs, resource entities, and power marketers and a similar but shorter set of requests to REPs, electric cooperatives, and municipally owned utilities (greater than 100 MW peak). Part I of the request was a Request for Admissions which contained a series of statements in which an officer of each company was directed to admit or deny, under oath, whether the company, or another company on its behalf, had engaged in the activities described in the statement. The request also sought production of documents related to the identified activities, as well as documents pertaining to opportunities for manipulation of the ERCOT market, strategies for overscheduling loads or resources in ERCOT, the benefits received as a result of overscheduling, and the benefits received from activities identified in the Request for Admissions. When allegations arose that one of the contractors for the California Power Exchange computer systems may have used its knowledge to help companies in the California market exploit weaknesses in that system, the Texas Commission expanded its Request for Admissions process to include the contractors who developed the ERCOT market and power systems.[46]

Commission Staff reviewed more than 175 responses from market participants. Responses to the Request for Admissions did not reveal widespread gaming of the ERCOT market. Some entities appear to have engaged in overscheduling for the purposes of hedging their exposure to the balancing energy market. These entities were not investigated in Project No. 25755, *PUC Investigation of Overscheduling in ERCOT in August, 2001,* because their load imbalance revenues for August, 2001 did not exceed the $1,000,000 threshold established by Staff. Other than the information provided by these entities, no gaming activities not already discussed in Project No. 25755 were reported.

Part I of the information request also asked respondents to indicate whether they had engaged in wash trades. The term "wash trades" was defined as sale of an electricity product to another entity together with a contemporaneous purchase of the same product at the same price. None of the respondents reported that they had engaged in offsetting trades solely for the purpose of increasing trading revenues. Reliant Resources, Inc. and Tractebel Energy Marketing, Inc. both reported that they had engaged in offsetting trades in conjunction with efforts at compliance with FASB 133, relating to hedging transactions. Several other entities reported that they had engaged in contemporaneous trades for "legitimate business purposes," which could include interbook trading or trades undertaken to correct a trade made in error.

[46] *PUC Investigation into Possible Manipulation of the ERCOT Market*, Project No. 25937.

In Part II of the information request, market participants were directed to provide a Certification of Ethical Conduct with regard to their activities in ERCOT. This issue is discussed in Section IV.C of this report.

### 2. Potential Gaming and Mitigation in ERCOT

As part of its presentation to the Legislative Oversight Committee, MOD identified certain other gaming opportunities that were possible in ERCOT or had been observed. Table 13 provides a summary of those gaming opportunities along with the measures that have been taken or are under consideration to mitigate the gaming opportunities. Many of the mitigation measures were addressed in Docket Nos. 23220 and 24770, and they are discussed in more detail in other sections of this report.

## Table 12: Summary of Analysis of Enron Strategies

| Enron Strategy | Reasons Why It Would Not Apply to ERCOT |
|---|---|
| **Export of Power** – Power exported from price cap area, exacerbating shortages and blackouts | • Very limited transmission linking ERCOT to other grid areas<br>• Offer cap applicable to entire ERCOT region |
| **Non-firm Export** – Receive congestion relief payment without relieving congestion | • Any congestion relief payments received by a QSE who fails to deliver the counterflow in real time would be exactly counter-balanced by charges for load and resource schedule imbalance, therefore the arbitrage opportunity does not exist. In addition, the QSE would incur an Uninstructed Resource Charge. |
| **“Death Star”** – Receive congestion-relief payments without relieving congestion; no net change in dispatch power | • ISO sees and controls all transmission into and out of constrained areas<br>• A party cannot schedule import through the North DC Tie into the North Zone, receive congestion relief payment to relieve South to North or West to North congestion, and then export the same power back through the DC Tie so that no power actually flows because ERCOT takes into account both scheduled imports and scheduled exports through the DC Ties in its flow models. |
| **Load Shift** – Artificially increases congestion and congestion costs | • Limit of 25% on amount of Transmission Congestion Rights any one company can hold reduces gaming opportunities<br>• ISO uses its own forecast and the submitted generation schedules to assess congestion; load schedules are not used<br>• ERCOT does not have a day-ahead energy market |
| **“Get Shorty”** – Paper trading of ancillary services that may not really exist | • ERCOT charges the responsible QSE for the cost of procuring ancillary services defaulted on which makes this strategy unprofitable |
| **“Wheel Out” –** Receive congestion relief payment without relieving congestion | • ERCOT has not assignment of local congestion cost, but it includes all line outages in its flow models which makes this strategy unsuccessful. |
| **“Fat Boy”** or **“Inc-ing”** – Manipulation of schedules to increase revenues | • Systematic underscheduling and matching overscheduling could occur, but there is no expectation of extraordinary gain under current market rules.<br>• Overscheduling occurred in August 2001 which resulted in high uplift charges to the market, but this strategy is no longer possible between zones because of direct assignment of congestion costs. |
| **“Ricochet”** – exploiting spread between Power Exchange (PX) and ISO markets | • ERCOT does not have a PX or spot energy market where prices are very different from the ISO-run balancing energy market. Therefore, this arbitrage opportunity does not exist. |
| **Selling non-firm energy as firm energy** | • ERCOT does not have a PX and does not operate an energy market other than the balancing energy market. |
| **Scheduling energy to collect congestion charge** | • Congestion relief payments and imbalance payments cancel each other out except in rare circumstances when ERCOT linear programming model does not reach a feasible solution. Steps have been taken to address this weakness in the model. |

## Table 13: Mitigation Measures for Gaming Potential in ERCOT

| Gaming Potential | Description | Effect/Market Impact | Mitigation Measure | Mitigation Status |
|---|---|---|---|---|
| **Bidding Strategies** | | | | |
| • Hockey Stick Bidding | Bid a few MW at $1000 in addition to regular bids | Price spikes during peak periods | Apply competitive sufficiency test (total quantity bid must be at least 115% of need). If test fails, mitigate market clearing price (MCP) | Commission approved MOD's Modified Competitive Solution Method in D-24770 on interim basis in June 2003. ERCOT Board (Board) approved PRRs 416 and 420. |
| • Exploitation of Price Reversal in Ancillary Services (A/S) Market | Offering lower quality A/S from units capable of producing higher quality A/S at times when lower quality services receive higher prices | Shortage of bids for higher quality A/S and higher prices for lower quality A/S | Require simultaneous selection of A/S bids | Commission ordered simultaneous selection in D-23220. Board approved PRR 342 in January 2003. |
| • Fractionalized Bidding in Replacement Reserve (RPRS) Market | Bid small amounts of power from different units into RPRS Market | Bidder receives multiple start-up cost payments which increases cost of RPRS | Revise Protocols to require bidding of whole units in RPRS market | |
| **Supply Manipulation** | | | | |
| • Holding Back A/S Bids in Expectation of a Higher Price Second Market | When ERCOT opens second market for A/S bids, price is determined by higher MCP of the two markets | Higher prices for A/S if second market also sets price for first market | When market insufficiency occurs, base price on 80% of A/S requirement. Also, settle each market separately. | Eighty percent rule implemented in Protocols. Commission ordered two-settlement system in D-23220. |
| • Physical Withholding Through Outage Manipulation | Reduce supply by (1) falsely declaring it unavailable (2) submitting inaccurate operating parameters (3) operating below dispatch instructions (4) strategic timing of forced or planned outages | Raises market prices; can create shortages even in times of excess capacity | Require binding resource plans and prior approval of planned maintenance; monitor outage rates | PRR 425 was initiated in 2003 to give ERCOT ability to coordinate resource outages. |
| • Economic Withholding | Submitting unjustifiably high bids for a large portion of capacity | Price spikes due to shortage of reasonably priced bids | Public disclosure of high bids; remove pivotal suppliers from bid stack before determining price; exclude highest 5% of bids in setting price | ERCOT Board implemented public disclosure. Commission approved MOD's Modified Competitive Solution Method in D-24770 on interim basis in June 2003. |

## Mitigation Measures for Gaming Potential in ERCOT (continued)

| Gaming Potential | Description | Effect/Market Impact | Mitigation Measure | Mitigation Status |
|---|---|---|---|---|
| **Manipulation of Load and Generation Schedules** | | | | |
| • Manipulation of Load and Generation Schedules | Misrepresentation of schedules to (1) put excess generation into market (2) rely on balancing market to serve load | Imbalance credits paid to entities misrepresenting their schedules | Direct assignment of interzonal congestion costs | Direct assignment was implemented on 2/15/02. Relaxed Balanced Schedule was implemented in November 2002. ERCOT plan to monitor Resource Plans proposed in 2003. |
| **Manipulation of Resource Plan Information** | | | | |
| • Understated Planned Operating Level of a Unit | Understate a unit's planned operating level in Resource Plan, especially when out-of-merit (OOM) order instructions are anticipated | Unit receives higher payments from ERCOT | Require binding resource plans; directly assign local congestion costs | Direct assignment of local congestion cost issue has led to consideration of moving to a nodal market design (D-26376). Also, ERCOT plan to monitor Resource Plans proposed in 2003. |
| • Misrepresentation of On/Off Status of Plants | An OOMed unit receives a start-up cost payment even if it is on line when called upon | Unit receives undeserved start-up payments | Verify if unit was off line through telemetry information | PRR 322 approved by ERCOT Board on 6/17/02. |
| • Payment for Non-Performance | Bidder selected and paid for RPRS but does not start-up unit and cannot be deployed | Bidder paid for service not rendered | Verify unit was on line through telemetry information | Approved by ERCOT Board. |
| **Price Chasing and Uninstructed Deviations** | | | | |
| • Price Chasing and Uninstructed Deviations | Engaging in price chasing or failing to follow schedule or dispatch instructions from ERCOT Operator | Contributes to frequency control problems and forces ERCOT to deploy costly additional resources to maintain frequency. | Increase penalty, reduce tolerance bandwidth as interim measure. Pay uninstructed energy dispatched in time "t" the price set at time "t+2" | Increased penalty, reduced tolerance bandwidth implemented by ERCOT Board. Payment of ex-post price ordered by Commission in D-23220 is still pending further action. |
| **Creation of Artificial Congestion** | | | | |
| • Creation of Artificial Congestion | (1) Overstate generation level in Resource Plan to create artificial congestion or (2) deploy strategically located units that would not be deployed absent the incentive to create congestion | Causing local congestion and being paid to relieve it increases uplift costs to market. | Directly assign local congestion costs | Direct assignment of local congestion costs was approved in D-23220, but debate over implementation has led to consideration of moving to a nodal market design (D-26376). |

## C. Standards of Behavior and Rulemaking on Enforcement of Wholesale Market Rules

MOD believes that the first and most important step in obtaining market participants' compliance with the market rules is the development of well-defined rules. The rules must be incentive compatible and leave little or no room for self-serving interpretations that can have a harmful impact on the market. It is therefore a priority of MOD to continuously work towards improving the ERCOT Protocols, making recommendations to change the rules where they allow for gaming behavior, clarify areas of ambiguity, address situations that are not contemplated by the Protocols, and generally improve the rules to align the interests of market participants with the efficient and reliable operation of the market.

Rule improvement, however, is a slow process, and this effort must be complemented with a vigilant market monitoring process that promptly identifies potential violations, and an investigation process that assesses responsibilities when a violation occurs and allows for the administration of penalties in a just and reasonable manner. Additionally, fairness requires that clear standards of behavior be established and well understood. This section discusses the efforts undertaken by MOD to make market participants aware of their obligations as they conduct business in the ERCOT markets.

Following the disclosure of the Enron gaming strategies and manipulations of the California market, MOD sent a request to market participants on June 12, 2002.[47] Part I of the request asked for information concerning trading activities that occurred during the period July 31, 2001 to June 12, 2002. Respondents were asked to state whether they had engaged in any of the activities engaged in by Enron in California, whether they had engaged in wash trades, and whether they had in any manner taken advantage of opportunities for manipulations of the ERCOT market. Part II, entitled "Certification of Ethical Conduct," asked respondents to commit to adhere to the following precepts:

A. You will not engage in any activity described in Part I of this memorandum;
B. You will not schedule or operate your resources or loads for the purpose of creating congestion;
C. You will not engage in economic withholding; i.e., you will offer service from your resources to ERCOT at their marginal costs, which may include your good faith estimate of opportunity costs;
D. You will not engage in physical withholding; i.e., you will not declare your resources to be unavailable to ERCOT for the purpose of increasing prices for ERCOT-procured services;
E. You will comply with all ERCOT rules, even when the ERCOT rules or your agreements with ERCOT do not specify a penalty for non-compliance;

[47] More specifically, two sets of information requests were issued: one request was issued to load serving entities, and the second request was issued to all QSEs, resource entities, and power marketers.

F. You will aid in identifying and closing loopholes in the ERCOT Protocols rather than exploiting them for short-term gain; and
G. You will provide accurate resource information to ERCOT and update your resource plans.

Market participants objected, claiming that Part II required them to take actions in response to standards of conduct developed without public input. They asked for an opportunity for public input by all stakeholders before the Commission establishes industry-wide standards of conduct. In response to such objections, the Commission modified the list of precepts. Market participants were asked to commit to:

A. Not engage in any activity described in Part I of the memorandum;
B. Not engage in physical withholding;
C. Comply with all ERCOT rules; and
D. Have sufficient management controls in place to ensure compliance with these precepts.

At the same time the Commission instructed MOD Staff to initiate a code of conduct rulemaking project that would provide an opportunity for public input in the development of standards of conduct for market participants.

In August of 2002, MOD initiated a Code of Conduct rulemaking. The purpose of the Code of Conduct was to specify clear rules for behavior for wholesale market participants engaging in buying and selling activities in the wholesale electricity market. Almost immediately, some market participants questioned the Commission’s authority to develop a rule that prescribes wholesale market participants’ behavior.

At the December 5, 2002 open meeting, the Commission responded by offering the ERCOT stakeholders the opportunity to develop their own Code of Conduct. The Commission’s proposal can be summarized as follows:

- The ERCOT stakeholders would develop a Code of Conduct that would become a part of the Protocols.
- The market participants would be expected to sign on to the Code of Conduct as a requirement for membership in ERCOT.
- The Code of Conduct would establish certain behavioral standards that would address elements such as withholding of production, creation of artificial congestion, wash trades, misrepresentation, availability reporting, information obligation, cooperation, physical feasibility, etc.
- Enforcement would be with the Commission.

In addition, the Commission directed Staff to proceed with developing a strawman rule independently. If the stakeholders were able to develop their own version of the Code of Conduct, and if that version addressed the concerns, the Commission would then incorporate it or part of it into the Staff’s proposed rule.

Over the next few months, the stakeholders developed a proposal that did not satisfy the enforceable Code of Conduct envisioned by the Commission.

The Commission then decided to change direction so that the outcome of this project would not be a Code of Conduct rule, but rather an Enforcement Rule. Market participants are often faced with ambiguities or situations that are not contemplated in the existing Protocols, the rule would contain a set of interpretative guidelines for such situations, while allowing for the problematic Protocol language to be clarified or otherwise addressed by an authorized ERCOT representative or through the Protocol Revision Process. The rule would also spell out the Commission's expectations regarding market participants' behavior, describe the standards and criteria the Commission would use when investigating a market activity, and the process for investigations. Finally, the rule would list market participants' obligations and prohibited activities that are specific and well defined. A draft rule was approved by the Commission in July 2003 and is being published in the Texas Register for public comments. It is anticipated that the final rule will be adopted in the Fall of 2003.

## D. Market Power Mitigation

### 1. Market Power Mitigation Provisions for Ancillary Services

#### a. Competitive Solution Method

The only mechanism limiting price spikes in the ERCOT-run energy and capacity markets in 2002 was a $1,000 limit on offer prices submitted by QSEs. While this cap was ordered by the Commission for the balancing energy service markets in Docket No. 23220, market participants voluntarily followed the $1,000 limitation for their capacity service bids as well.

MOD remains concerned about the potential for gaming within and near the bounds set by the offer price caps, however. Market prices may still rise to $1,000 for reasons other than true market scarcity, and in Docket No. 24770 MOD has advocated an automatic mitigation procedure to address such situations. The proposal has drawn strong opposition primarily from generation owners. Table 14 and Table 15 show the percentage of bids for each QSE in 2002 that fall into certain price ranges. Some QSEs never bid near the offer price caps, but others did so a significant percentage of the time. For the market as a whole, 1.8% of the Up Balancing bids were within $200 of the $1000 bid cap and 9.9% of the Down Balancing bids were within $200 of the ($1000)/MWh bid cap.

The proposal, called the Competitive Solution Method (CSM), differs from automatic mitigation procedures used in other markets in that it does not evaluate individual bids against historical benchmarks. Instead, a two-part Competitive Sufficiency Test (CST) evaluates conditions in the market as a whole. The conditions for a market to pass are (a) total bids to provide a service must amount to at least 115% of what ERCOT needs, and (b) the market clearing price must not be set by a pivotal bidder.

If a market were to fail the CST, the first step would be to post an indicative MCP (the market clearing price that would result with no mitigation) and allow bidders time to submit more offers. The CST would then be applied to the results of the extended market. If the extended market were to fail the CST, an MCP limit would be calculated by:

1. Constructing a bid stack comprised of only non-pivotal bidders;
2. Eliminating the highest-priced 5% quantity of the non-pivotal stack; and
3. Multiplying the remaining high bid price by 1.5.

MOD has proposed CSM for the Day-ahead capacity markets run by ERCOT. For the hour-ahead balancing energy markets, MOD has proposed a modified version of CSM that would be triggered only when all available bids were deployed.

**Table 14: Percentage of Up Balancing Bids in 2002 by Price Range[48]**

| QSE | Total Bids | <$300 | $300-$500 | $500-$800 | >=$800 | Total |
|---|---|---|---|---|---|---|
| AMERICAN ELECTRIC POWER SERVICE CORP | 111,115 | 98.8% | 0.0% | 0.0% | 1.2% | 100.0% |
| ANP FUNDING I LLC | 8,339 | 99.6% | | | 0.4% | 100.0% |
| AQUILA ENERGY MARKETING CORP | 40,928 | 90.7% | 0.1% | 0.0% | 9.2% | 100.0% |
| AQUILA ENERGY MARKETING CORPORATON (SQ1) | 183 | 88.5% | | | 11.5% | 100.0% |
| AUTOMATED POWER EXCHANGE | 66,011 | 92.5% | 0.3% | 0.1% | 7.1% | 100.0% |
| BTU QSE SERVICES INC | 13,970 | 96.1% | 1.1% | 1.4% | 1.4% | 100.0% |
| CALPINE POWER MANAGEMENT LP | 27,568 | 98.3% | 0.0% | 0.2% | 1.5% | 100.0% |
| CITY OF AUSTIN DBA AUSTIN ENERGY (QSE) | 43,102 | 93.9% | 5.8% | 0.1% | 0.3% | 100.0% |
| CITY OF GARLAND (QSE) | 17,427 | 100.0% | | | | 100.0% |
| CONSTELLATION POWER SOURCE INC | 6,952 | 100.0% | | | | 100.0% |
| CONSTELLATION POWER SOURCE INC B | 260 | 100.0% | | | | 100.0% |
| CORAL POWER LLC | 28,574 | 99.3% | 0.2% | 0.2% | 0.3% | 100.0% |
| DYNEGY POWER MARKETING INC | 31,996 | 99.7% | 0.1% | 0.2% | | 100.0% |
| EXELON POWER TEAM | 8,392 | 100.0% | | | | 100.0% |
| FPL ENERGY POWER MARKETING | 11,710 | 100.0% | | | 0.0% | 100.0% |
| FPLE PMI BASTROP FPL ENERGY POWER MARKETING, INC.(SQ1) | 4,520 | 99.9% | | | 0.1% | 100.0% |
| LOWER COLORADO RIVER AUTHORITY (QSE) | 31,220 | 90.7% | 2.1% | 2.5% | 4.7% | 100.0% |
| MIRANT AMERICAS ENERGY MARKETING LP | 38,816 | 81.7% | 13.1% | 0.0% | 5.1% | 100.0% |
| PG AND E ENERGY TRADING POWER LP | 14,095 | 91.6% | | 8.4% | | 100.0% |
| RELIANT ENERGY ELECTRIC SOLUTIONS (QSE) | 528 | 100.0% | | | | 100.0% |
| RELIANT ENERGY SERVICES INC (SQ2) | 14,557 | 100.0% | | | 0.0% | 100.0% |
| SOUTH TEXAS ELECTRIC CO OP INC (QSE) | 12,995 | 100.0% | | | | 100.0% |
| TENASKA POWER SERVICES CO | 58,447 | 99.5% | | 0.0% | 0.5% | 100.0% |
| TEXAS GENCO GP LLC (SQ1) | 82,787 | 99.9% | 0.0% | 0.0% | 0.0% | 100.0% |
| TEXAS GENCO LP (QSE) | 5,861 | 100.0% | | | | 100.0% |
| TXU ELECTRIC CO (QSE) | 10 | 100.0% | | | | 100.0% |
| TXU PORTFOLIO MANAGEMENT COMPANY LP (QSE) | 136,603 | 100.0% | 0.0% | 0.0% | | 100.0% |
| **Total** | **816,966** | **96.9%** | **1.1%** | **0.3%** | **1.8%** | **100.0%** |

48 A blank cell means there were no bids in that price range.

**Table 15: Percentage of Down Balancing Bids in 2002 by Price Range[49]**

| QSE | Total Bids | >($300) | ($300)-($500) | ($500)-($800) | <=($800) | Total |
|---|---|---|---|---|---|---|
| AMERICAN ELECTRIC POWER SERVICE CORP | 171,642 | 96.3% | 0.0% | 0.0% | 3.7% | 100.0% |
| ANP FUNDING I LLC | 25,317 | 79.7% | 0.0% | 0.3% | 20.0% | 100.0% |
| AQUILA ENERGY MARKETING CORP | 93,519 | 66.0% | 5.4% | 6.9% | 21.7% | 100.0% |
| AQUILA ENERGY MARKETING CORPORATON (SQ1) | 323 | 69.0% | 6.8% | 7.1% | 17.0% | 100.0% |
| AUTOMATED POWER EXCHANGE | 59,081 | 69.4% | 0.6% | 0.2% | 29.8% | 100.0% |
| BTU QSE SERVICES INC | 45,265 | 98.4% | 1.2% | 0.1% | 0.2% | 100.0% |
| CALPINE POWER MANAGEMENT LP | 46,767 | 65.2% | 0.0% | 5.3% | 29.4% | 100.0% |
| CITY OF AUSTIN DBA AUSTIN ENERGY (QSE) | 55,441 | 93.8% | 0.1% | 0.1% | 6.1% | 100.0% |
| CITY OF GARLAND (QSE) | 36,078 | 99.7% | 0.0% | 0.0% | 0.2% | 100.0% |
| CONSTELLATION POWER SOURCE INC | 14,761 | 85.9% | 4.4% | 4.8% | 4.9% | 100.0% |
| CONSTELLATION POWER SOURCE INC B | 29,811 | 69.5% | 15.3% | 0.0% | 15.3% | 100.0% |
| CORAL POWER LLC | 76,893 | 97.5% | 0.2% | 0.4% | 1.9% | 100.0% |
| DYNEGY POWER MARKETING INC | 55,365 | 98.4% | 1.5% | 0.0% | | 100.0% |
| EXELON POWER TEAM | 14,248 | 84.1% | | | 15.9% | 100.0% |
| FPL ENERGY POWER MARKETING | 19,409 | 86.3% | | | 13.7% | 100.0% |
| FPLE PMI BASTROP FPL ENERGY POWER MARKETING, INC.(SQ1) | 8,834 | 78.7% | | | 21.3% | 100.0% |
| FPLE_WIND_FPL ENERGY POWER MARKETING INC.(SQ2) | 9,465 | | | | 100.0% | 100.0% |
| LOWER COLORADO RIVER AUTHORITY (QSE) | 66,606 | 91.3% | 0.3% | 1.3% | 7.1% | 100.0% |
| MIRANT AMERICAS ENERGY MARKETING LP | 105,118 | 82.0% | 11.0% | 0.1% | 6.9% | 100.0% |
| PG AND E ENERGY TRADING POWER LP | 27,773 | 95.7% | 0.1% | 4.3% | | 100.0% |
| RELIANT ENERGY ELECTRIC SOLUTIONS (QSE) | 2,140 | 100.0% | | | | 100.0% |
| RELIANT ENERGY SERVICES INC (SQ2) | 39,795 | 72.8% | | | 27.2% | 100.0% |
| SOUTH TEXAS ELECTRIC CO OP INC (QSE) | 22,992 | 99.5% | 0.3% | 0.1% | | 100.0% |
| TENASKA POWER SERVICES CO | 71,459 | 73.4% | | | 26.6% | 100.0% |
| TEXAS GENCO GP LLC (SQ1) | 151,574 | 94.2% | | 2.9% | 2.9% | 100.0% |
| TEXAS GENCO LP (QSE) | 13,169 | 100.0% | | | | 100.0% |
| TXU ELECTRIC CO (QSE) | 4 | 100.0% | | | | 100.0% |
| TXU PORTFOLIO MANAGEMENT COMPANY LP (QSE) | 109,400 | 100.0% | | | | 100.0% |
| **Total** | **1,372,249** | **87.1%** | **1.8%** | **1.2%** | **9.9%** | **100.0%** |

49 A blank cell means there were no bids in that price range.

### b. Two-settlement System for Procurement of Ancillary Services

Typically, ancillary service bids are selected only in the Day-ahead period; as needed, additional capacity may be procured during the Adjustment Period for each Operating Hour. In the absence of insufficiency, the original Protocols specified that all the procured capacity for each ancillary service would be settled at a single Market Clearing Price for Capacity based on the entire quantity procured in the Day-ahead period as well as the Adjustment Period. However, this created a situation where suppliers selected in the Day-ahead period could influence the MCPC that would be paid to their already selected bids by manipulating their unselected bids. This perverse incentive was removed by amending the Protocols to use a two-settlement system for the procurement of ancillary services, whereby the Day-ahead period procurements are settled at an MCPC for each ancillary service that is set at the time that the Day-ahead selected A/S bids are announced. A second MCPC for each ancillary service, determined at the end of the Adjustment Period, is used to settle any additional procurements of ancillary service capacity taking place during the Adjustment Period for each Operating Hour. The revised Protocol went into effect on 10/1/2002.

### c. 80% Rule for Periods of Market Insufficiency

When the last megawatt cleared is used to set the market price, then all bidders possess market power during periods of bid insufficiency. In order to discourage withholding of offers to induce bid insufficiency, the Protocols contain a provision to pay the MCPC that would have resulted if ERCOT had procured only eighty percent (80%) of the capacity procured prior to declaration of insufficiency.

### d. Simultaneous Selection of Ancillary Services

The original Protocols (which are still in effect pending system upgrades) require ERCOT to procure certain ancillary services sequentially through an auction, in the following order: Regulation Down, Regulation Up, Responsive Reserves, and Non-spinning Reserves. Bidders may bid their capacity for one or more of these services, and once the bids are submitted, the markets are essentially cleared as four separate auctions. Since the same block of capacity could be potentially used for more than one service, clearing these markets sequentially may not produce the most efficient allocation of capacity to services. For example, a block of capacity capable of providing either Regulation Up or Responsive Reserves that would optimally be used for Responsive Reserves might instead be cleared for Regulation Up, since at the time of clearing Regulation Up, there is no consideration of the impact of choices made now on ancillary services as a whole. This methodology results in the possibility of price reversals, where the clearing prices for Responsive Reserves may exceed the clearing price for Regulation-up (the higher grade service), or the clearing price for Non-spinning Reserves may exceed the clearing price for Responsive Reserves (the higher grade service). Price reversals in turn create perverse incentives for bidders to game the auction by misrepresenting cost or capability, which in turn can result in misallocation of resources and reliability problems due to artificial shortages of Regulation Up or Responsive Reserves bids.

In Docket No. 23220, Order on Rehearing, the Commission ordered that ERCOT procure ancillary services through use of simultaneous optimization for assignment of resources to ancillary service products. Simultaneously optimizing the procurement of the required ancillary services will produce the most efficient result. In this case, efficiency is defined as maximizing the overall value to ERCOT of the services procured, and is achieved by selecting the mix of services which minimize the as-bid cost. This approach is generally consistent with that used by other markets, such as New York and California, and with the FERC SMD NOPR. Ultimately, efficiency may be further improved by the co-optimization of reserves and energy, which is the direction other markets are heading. This would require a day-ahead energy market, assuming that capacity reserves continue to be procured day-ahead in ERCOT.

A Protocol Revision Request to implement the simultaneous optimization of Regulation Up, Responsive Reserves and Non-Spinning Reserves was developed by MOD working through the stakeholder process. The ERCOT Board approved the PRR in January of 2003. This PRR requires system changes before it can be implemented.

### 2. Market Solution Method for Balancing Energy Service

When local congestion occurs, there is often a very limited number of units which can relieve the congestion by providing balancing energy (Local Balancing Energy). In these situations, applying a bid based, uniform market clearing price approach can easily lead to non-competitive outcomes. For this reason, the Protocols include a Market Solution Test applied to Local Balancing Energy procurements, as follows: "A Market Solution exists when at least three unaffiliated Resources, with capacity available, submit bids to ERCOT that can solve a circumstance of Local Congestion and no one bidder is essential to solving the Congestion." The Market Solution function was implemented May 6, 2002. Prior to that time, all Resources deployed to resolve local transmission congestion in real time were paid as OOME. After May 6, 2002, resources providing Local Balancing Energy were paid based on the MCPE and their unit specific bid premiums when a Market Solution exists, while Resources providing Local Balancing Energy where no Market Solution exists are paid as OOME.

Beginning about July 12, 2002, initial settlements for Local Balancing Energy Service averaged approximately $1 million per day. Concerns were raised that the methodology to determine a Market Solution condition might not be working as intended. It was observed that some units with up premiums at $999 were being paid as bid, while other units with lower premiums were not dispatched.

After the issue was raised, an extensive study was performed by ERCOT on the Market Solution function. ERCOT determined that Local Balancing Energy was being properly deployed; however, the Market Solution test was not always correctly identifying the presence (or lack) of a Market Solution. False Market Solutions were identified because the logic did not properly take into account all the possible constraints in the balancing energy Market Solution to reflect the accurate value of available MW from individual units for local congestion.

ERCOT revised its Market Solution Test logic, effective December 24, 2002, and is resettling the balancing energy markets as needed for the affect time period, May 6, 2002, through trade date December 23, 2002, as needed.

### 3. Stakeholder Method to Reduce Local Congestion Costs

The ERCOT Protocols were written under the theory that ERCOT should not use command and control instructions unless the market did not provide the capacity and energy needed for reliable operation. Out-of-merit instructions are command and control instructions that ERCOT Operators use mainly to clear local congestion. These instructions take three forms: OOME Up – an increase in generation for a unit already in operation; OOME Down – a decrease in generation for a unit already in operation; and OOMC – an instruction to start a generator that was not planned for operation.

OOM costs are uplifted to load in ERCOT. Originally, the compensation for each OOM instruction was designed to ensure that each generator's costs were recovered. However, because the OOM rates were set to allow the most expensive unit to cover its costs, the majority of units were receiving more than their operating costs. To accommodate different types of generators with different cost structures, the Protocols were changed on July 31, 2002 to adopt several generation unit categories for OOME with technology-specific cost structures, thus lowering the cost of OOME deployment. Under this cost structure, OOME payments are the product of a generic technology-specific unit heat rate and a fuel price based on a natural gas price index. Compensation for OOMC was also changed such that generating units are paid only for actual start-ups incurred, and these payments are also based on a set of generic generator characteristics. Further refinements to OOME and OOMC pricing structures are still in the discussion stage at ERCOT, with the potential to further reduce uplift in ERCOT.

According to ERCOT's calculations, the changes in OOM reimbursement that were instituted on July 31, 2002 (PRRs 335-338) would have decreased OOME down payments to non-wind generators by 30% if they had been instituted at the ERCOT wholesale market opening on July 31, 2001.[50] Additional refinement of the generation unit categories for OOME compensation could further reduce OOME payments by an estimated 20%.[51]

The ERCOT stakeholders are now refining the ERCOT market – a natural and appropriate evolution of the stakeholder process – and have identified the following as potential ways to further reduce local congestion costs:

[50] *ERCOT Study on Local Congestion Costs*, as summarized by Eric S. Schubert, Market Oversight Division, PUC Project No. 26376 (filed January 10, 2003).

[51] *TXU Energy's Response to Commissioner Parsley's Request at the January 14 Workshop*, TXU Energy, PUC Project No. 26376, page 4 (filed January 23, 2003).

**Table 16: Potential Future Market Evolutions**

| Methodology | Description | Date | Estimated Savings | |
|---|---|---|---|---|
| | | | Capacity (OOMC) | Energy (OOME) |
| Enhancements to Generic Unit Costs for OOM | Creating more technology-specific cost structures and thus lowering the cost of OOME deployment | Future date[52] | Savings unknown, possibly as much as 23% of non-wind OOMC | Up to an additional 23% (approximately $12.88 million[53]) of non-wind OOME if implemented for entire market open |
| RMR | Reducing RMR capacity payments by paying generators only for the incremental fixed costs that they incur to keep their units in operation (*i.e.*, additional labor, materials, etc. needed to keep the unit in operation) plus a 10% adder, if the unit is available for operation in the summer | Future date[54] | Possible savings unknown | Possible savings unknown |
| No OOME down for wind resources in McCamey | Do not make payments for OOME down service to wind generators in the McCamey region of west Texas | Spring 2003 | N/A | Estimated $12 million in savings |
| No OOME Down for GPAs | OOME down would not be paid to generators in Generation Pocket Areas (GPAs) where too much generation has been or will be built in the area to allow the generators in that region to operate at full capacity | Future date[55] | N/A | Savings unknown without further analysis |

# E. Market Information Transparency

## 1. Definition and Treatment of Confidential Information

In June 2002 the ERCOT Board approved PRR 327, which changed the way ERCOT defines and treats confidential information. Previously, Section 1 of the Protocols had permitted market participants to self-declare any information as confidential, with some specific exceptions. PRR 327 amends this section by enumerating the specific types of information that are to be protected. In addition, the Protocols now specify the length of time that each class of confidential information is to be protected. For example, information on specific bids by QSEs is protected for six months after the applicable operating day, after which the information may be released to any requesting party.

52 This issue has been discussed at Congestion Management Working Group (CMWG) meetings, but no draft PRR is being prepared at this time.

53 23% of non-wind OOME = 23% x $56,000,000 = $12,880,000.

54 A PRR for this methodology is currently being drafted by the RMR Task Force and should be completed in February 2003. This pricing methodology could be implemented by the summer of 2003.

55 This issue has been discussed at CMWG meetings, but no draft PRR is being prepared at this time. However, this issue is essentially the same concept as the concept for the OOME Down for wind resources. If that concept is adopted, only a few minor changes would be necessary to implement the OOME Down methodology for GPAs.

P.U.C. Substantive Rule §25.362(e), which was adopted by the Commission in February 2003, further clarifies that operating information collected by ERCOT is presumed to be non-confidential unless it is specifically listed in the Protocols as protected information. Table 17 lists the specific information that is protected under the Protocols.

**Table 17: Information Protected Under ERCOT Protocols**

| Information | Duration of protected status |
|---|---|
| Schedule Control Error identifiable to a specific QSE | 7 days |
| Bids or pricing information identifiable to a specific QSE | 180 days |
| Status of resources | |
| Resource plans | |
| Energy and Ancillary Service schedules identifiable to a specific QSE | |
| ERCOT dispatch instructions to a specific QSE | |
| Raw and adjusted metered load data identifiable to a specific QSE | |
| QSE-specific settlement statements | |
| Aggregated metered load data identifiable to a specific LSE | 365 days |
| Data related to generation interconnection requests | No expiration |
| Resource specific information on costs, design and engineering | |
| TCR information identifiable to a specific TCR account holder | Six months after the year the TCR was effective (identities of purchasers released after auction is concluded) |
| Renewable Energy Credit account balances | Three years after applicable settlement period |
| Information that is not submitted to or collected by ERCOT pursuant to the requirements of the Protocols or operating guides | As designated by submitting party |
| Proprietary customer information | No expiration |
| Software | According to vendor requirements |

In addition, Section 1 of the Protocols now calls for identifying QSEs if their bid prices are greater than $300 for Up Balancing Energy Service (or less than -$300 for Down Balancing Energy Service). A list of such bidders for the entire operating day is published on the ERCOT web site the next day. The list does not specify the specific price or quantity of any QSE's bid curve.

The amended protocol still allows market participants to self-designate confidential information, but this right is limited to information that is *not* normally provided to ERCOT under the Protocols or the Operating Guides. For example, information that ERCOT only sees during a dispute resolution proceeding could be declared confidential by the party providing the information.

Another provision added by PRR 327 is recognition that the Commission may reclassify protected information as non-confidential. Reclassification would happen after the party that supplied the information to ERCOT had been advised. The party would then have an opportunity to ask for a hearing prior to release of the information. P.U.C. Substantive Rule §25.362(e) contains a similar provision and specifies a procedural timetable for parties to file challenges.

### 2. Information on Bilateral Contracts

On April 17, 2003 the Commission asked for public comment on a proposed rule to require quarterly reports on electricity and capacity sold under bilateral contract. Although bilateral arrangements are scheduled through ERCOT and constitute between 90% and 95% of the ERCOT energy market, ERCOT has no information on the associated prices.

The Commission's proposed rule is modeled after the FERC's Electric Quarterly Reports. The Commission's quarterly reports would require generation resource owners and power marketers to report information on each energy transaction (including price and quantity) and on each electricity contract in effect for the reporting period. The reports would expand MOD's ability to monitor market power in the bilateral market, and would also enable the construction of price indices and other market metrics.

The proposed rule includes a procedure by which the Commission could conduct a contested-case proceeding to determine whether information contained in the reports should be made public. Until such a determination is made, however, reports would be treated as confidential in accordance with current Commission procedural rules.

A final version of the rule is expected to be considered for adoption by the Commission by mid-summer 2003.

## F. Market Design Issues

### 1. Direct Assignment of Local Congestion Rents

Under the ERCOT Protocols, intrazonal congestion management costs are borne by all load serving entities on a load ratio basis. There is no limit on the amount of intrazonal congestion management costs that can be incurred and allocated to load serving entities. In order to place a reasonable limit on the amount of congestion management costs borne by entities that did not cause the congestion, and in order to reduce the potential for gaming of transmission congestion, the Commission's final order in Docket No. 23220 required ERCOT to implement direct assignment of local congestion rents beginning six months after the incurred cost of clearing local congestion reached $20 million during a twelve-month period.[56] The $20 million threshold was reached on March 5, 2002, barely eight months after the market began. Local congestion costs continued to mount in 2002, ending with a total of $186.3 million for the year and $212.2 million for the first 17 months of the market.

With the help of its senior advisor, Shmuel Oren, MOD developed a revenue neutral method for the assignment of local congestion fees. In this method generators are charged (or paid) congestion fees that are equal to their shift factor multiplied by the flow induced by their metered output (after congestion is relieved) on the congested intrazonal interfaces. The net zonal

[56] As noted earlier in this report, *inter*zonal congestion management costs were also uplifted to all load serving entities when the market began, and the Commission imposed a similar $20 million threshold on interzonal congestion costs in the final order in Docket No. 23220. That threshold was breached on August 15, 2001, and direct assignment of interzonal congestion costs was implemented on February 15, 2002.

revenues or shortfalls resulting from the assignment of local congestion fees are allocated back to the generators in the zone on the basis of metered output on a *pro-rata* share. The congestion fee can be interpreted as a revenue neutral system of side payments between generators aimed at homogenizing the cost among generators so as to achieve an efficient rationing of scarce transmission resources and eliminate gains from gaming schedules.

The proposed methodology can be viewed as an alternative way for implementing locational marginal cost prices which is designed to be "ERCOT friendly". This implementation takes advantage of sparse local congestion and is adapted to the two step congestion management approach that accommodates portfolio balancing bids with zonal redispatch as needed. The intent of the methodology is to make the design of the underlying zonal model sustainable and consistent with fundamental economic principles.

After much discussion, market participants have raised various objections to MOD's proposal, and no consensus has emerged on any specific method for assigning local congestion rents.

Although MOD's proposal was intended to preserve the zonal system, MOD and various market participants have questioned whether a different market design would be more suited to ERCOT's needs in the long run. The level of local congestion costs is unacceptably high, and it is apparent to MOD that the existing Protocols contain incorrect incentives which encourage market participants to play the DEC game, thereby increasing congestion costs. As described in a report by Shmuel Oren filed in Docket 23220,[57] the potential for gaming exists whenever there a predictable gap between how congestion relief is paid and how the costs of these payments are allocated. If local congestion costs are socialized, a QSE can game the real time dispatch by scheduling its generators to run at a level that would induce instructed deviations to alleviate the congestion the QSE created. This gaming opportunity is known as the DEC game (for decremental energy instructions).

It is also apparent that the lack of locational price signals within a zone encourages developers to build new resources in locations that exacerbate congestion costs and result in unnecessary transmission construction. Zonal prices do not reflect the price differentials of local congested areas within a zone. The location of transmission line congestion will change over time as supply and demand conditions change. Demand will increase fastest in rapidly growing metropolitan areas of ERCOT, while supply will change as new generating units are being built and old generating units retired. Direct assignment of local congestion rents will help LaaRs to have an increasing presence in the ERCOT market over time.

In the new world of competitive wholesale and retail markets, supply and demand will happen with change more frequently and more quickly. As a result, transmission constraints will occur more rapidly in locations that are less predictable ways. The rapid deployment of wind power in West Texas – and the resulting transmission bottleneck that has even damaged equipment – is an example of the problems that can occur in a deregulated market with poor price signals.

[57] Docket No. 23220, *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, "Report to the Public Utility Commission of Texas on the ERCOT Protocols," Docket No. 23220, February 9, 2001.

Standard economic theory states that the most efficient way to allocate scarce resources such as transmission capacity is to use marginal pricing. In its Notice of Proposed Rulemaking for its standard market design (SMD), FERC recognizes the importance of using marginal prices to allocate scarce resources. ERCOT learned this lesson in August 2001, when zonal congestion skyrocketed because those costs were uplifted to all load rather than assigning of zonal congestion fees to resources. Zonal congestion costs have plummeted since February 15, 2002, when ERCOT began assigning zonal congestion fees to allocate transmission capacity between zones.

Locational prices, established by assigning local congestion fees, encourage market participants to develop demand side resources or distributed generation to alleviate local constraints as an alternative to non-market means such as OOME Up instructions, RMR units, or transmission construction. Locational pricing discourages the piling of generation at transmission-constrained site and likely would have prevented the siting 750 to 1,000 MW of wind farms behind a 400 MW transmission constraint in the McCamey area. Assigning local congestion fees would have directed developers of wind power to choose one of the other numerous potential sites within ERCOT to produce renewable energy.

### 2. Reevaluation of Market Design

In November 2002 the Commission began a series of workshops focused on transmission congestion and market design issues. The activity is being conducted in Project No. 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas.* The first workshop was designed as primarily educational and presented tutorials on congestion prices, transmission rights, day-ahead markets, and real-time spot markets. A panel of knowledgeable market participants provided comments and questions on each of the tutorials. In the second workshop, the operation of the Relaxed Balanced Schedule, which had been recently implemented in ERCOT, was reviewed, and market participants described various proposals for a day-ahead energy market. A panel of market participants discussed the benefits and need for a day-ahead market as well as the issues pertaining to centralized day-ahead, security-constrained unit commitment. In the third workshop, which took place in January 2003, educational information was provided on managing congestion in the ERCOT zonal system versus managing congestion in a nodal system. In addition, market participants gave their views on preferred market designs, including the nodal model, the Zonal-ERCOT-Nodal (ZEN) model proposed by LCRA, and the Nodal-When-You-Need-It model proposed by MOD Staff and Dr. Oren. Review and debate of market design issues is continuing in 2003.

## G. Resource Plan Accuracy

Each QSE must submit a Resource Plan to ERCOT in the day before the operating day. The Resource Plan contains operational information about specific generating units and LaaRs. It indicates the availability of each of the QSE’s resources along with the planned operating level and operating limits of these resources.

In the initial market design, Resource Plans were intended to be used for planning purposes and for ERCOT to conduct studies in advance of real time for system reliability purposes. They were not intended for real-time operational purposes or for financial settlement. In practice, ERCOT has found it necessary to rely on the Resource Plan for these purposes in the absence of viable alternatives. As a result, it is very important that the information contained in the Resource Plan be binding and accurate, and that it be updated as close to real time as possible. Difficulties emerge, however, because the Resource Plan is not designed to be readily updated near real-time, and it is burdensome for QSEs to keep it continuously updated. Further, ERCOT systems do not have the ability to efficiently track QSE changes to Resource Plans. As a result ERCOT does not have the proper tool to track available capacity and unit offline status, to properly assess the operational characteristics of generating units and load resources, and to know with certainty how individual resources are going to be operated.

In other electricity markets, the market design calls for market participants to submit unit specific bid curves and unit specific schedules, which provide the ISO with the unit specific operational information it needs. The reliance on the Resource Plan for such information in ERCOT is a by-product of a portfolio based market design that distinguishes ERCOT from other markets.

A change to the Protocols, PRR 359, was introduced to improve the information that QSEs provide regarding the operating limits of their resources. This change addresses some but not all of the operational problems faced by ERCOT. According to ERCOT operating staff, addressing the remaining issues may require the following:

- Improved Resource Plan accuracy overall
- Increased capability of ERCOT systems to track changes to Resource Plans made by QSEs
- Increased capability of ERCOT systems to “snapshot” operating levels when certain instructions for deployment of units out of merit order are given
- Increased capability of ERCOT systems to allow updates to Resource Plans closer to real time operations. Currently ERCOT does not allow changes to Resource Plans close to real time in order to avoid gaming opportunities.

MOD has observed that violations of the requirement to provide accurate information and update the Resource Plan occur frequently, and that they affect the efficient and reliable operation of the ERCOT markets. However, some market participants have been successful in their effort to improve the accuracy of their Resource Plan information over time. ERCOT has recently introduced a proposal to measure QSEs’ Resource Plan performance, and thereby provide more incentive for all QSEs to follow this path. The performance metrics initially proposed were tested over the months of February through June 2003 and the results analyzed. Discussions regarding adjustments to and refinement of these performance metrics are under way between ERCOT staff and the ERCOT QSE Project Managers Working Group.

## H. Relaxed Balanced Schedule

The Balanced Schedule requirement of the ERCOT Protocols requires QSEs to submit Day-ahead balanced energy schedules. That is, for each 15-minute settlement interval for the following day, the QSE’s scheduled supply is required to match its scheduled obligation on a

MW-for-MW basis. The Balanced Schedule requirement also applies to ancillary services, although ERCOT can be designated as providing a portion or all of a QSE's ancillary services through an ERCOT-administered ancillary service auction.

The intent of the Balanced Schedule requirement was initially to preclude QSEs from relying on the ERCOT-administered balancing energy market as part of their resource portfolios, except to cover any underestimated "balancing" energy needs. The Balanced Schedule requirement was advocated and preferred by the majority of ERCOT Stakeholders who participated in designing the market. However, MOD anticipated that elimination or relaxation of the Balanced Schedule requirement would increase the liquidity of forward energy markets, and possibly serve as the impetus for launching a private exchange for day ahead and other forward energy products. In Docket No. 23220, the Commission, following MOD's recommendation, ordered ERCOT to consider and report on the technical implications of relaxing or eliminating the Balanced Schedule requirement.

Subsequently, ERCOT stakeholders created a Balanced Schedule Working Group to evaluate the technical implications of relaxing or eliminating the Balanced Schedule requirement. A distinction was made between Relaxed Balanced Schedule (RBS) and Unbalanced Schedule (UBS). Under RBS, a QSE estimates its total load requirement for each interval for the next day's operations, but is permitted to schedule all, some, none, or an excess of that load in each interval. The QSE must schedule the amount of resources that it intends to provide and an equal amount of load, such that the amount of obligation and the amount of supply scheduled match for every interval in the next 24-hour period. In contrast, UBS would allow a QSE to schedule some, all or none of its obligation and supply for the next operating day independently of each other.

In March 2002, the ERCOT stakeholder working group concluded that eliminating the Balanced Schedule requirement completely would require significant changes to the ERCOT operations and settlement systems, and recommended instead the adoption of RBS. However, ERCOT Staff was concerned about a possible impact on frequency control. Resource Plan accuracy and timely updates were also a concern. Protocol Revisions were submitted to address some of these concerns.

RBS, along with the necessary Protocol changes, were approved by the ERCOT Board in October 2002 and implemented on November 2, 2002, with the provision that ERCOT would have the authority to suspend RBS in the following six months if it determined that reliability was adversely affected by its implementation.

In the first two months of implementation, no significant changes were observed in the volume of balancing energy deployed by ERCOT. Market participants appeared to be initially wary of the risk of exposure to the balancing price.

By the end of 2002, ERCOT had not experienced any noticeable frequency control problems due to RBS, and the amount of Day-ahead capacity reserves required did not seem to have increased. MOD continues to monitor and analyze market participants' reliance on RBS and its effects on the market.

## I. McCamey Area Transmission Constraints

Texas finished 2002 three years ahead of schedule in meeting the Legislature's goal for new renewable generation capacity. Nearly all of this progress was attributable to wind power in West Texas. So much wind power was added, however, that the existing transmission system was not capable of delivering all the power that could be generated. Equipment was damaged, and wind farms were routinely ordered by ERCOT system operators to curtail output in order to maintain safety and reliability standards. The problem was – and still is – concentrated in the McCamey area, where in 2002 installed wind power capacity was almost twice the area's transmission export capacity.

Local congestion management costs attributable to wind power in the McCamey area amounted to around $9 million for all of 2002. Nearly all of these costs were due to curtailment instructions issued by ERCOT to wind generators whenever the McCamey transmission lines were loaded to their operating limits.

MOD attempted to address the West Texas wind power problem on two fronts: by exploring options for more transmission, and by eliminating the financial incentives for "piling on" to problem sites that are already known. Project No. 25819[58] was created as a forum to address the transmission issues. At the same time, MOD attempted to address the financial issues through the ERCOT stakeholder process.

The ultimate solution will be to get more transmission out to where the wind power is, and there is widespread consensus on the need for new lines. Several wires companies are constructing new lines and upgrading existing lines to alleviate the transmission constraints. Nevertheless, transmission under construction will still fall short of the wind power capacity now in the McCamey area, and will continue to be insufficient up through 2006. (Table 18)

**Table 18: McCamey Area Projected Generation and Transfer Capability[59]**

| | Wind Power Generation Capacity (MW) | Transfer Capability of Transmission System (MW) | Difference |
|---|---|---|---|
| **2002** | 758 | 300 | 458 |
| **2004** | 758 | 500 | 258 |
| **2006** | 758 | 650 | 108 |

Siting, approving, and building a transmission line take much longer than putting up a wind farm, and this time mismatch makes existing rules and laws governing new transmission problematic. MOD believes that planning will be a crucial part of a transmission solution. In the future, it may be necessary to anticipate where the best wind potential is located, rather than waiting for signed interconnection agreements for specific projects. Currently, planning is

[58] *PUC Proceeding to Address Transmission Constraints Affecting West Texas Wind Power Generators*, Project No. 25819.

[59] Source: Transmission capability estimates provided by Stuart Nelson, LCRA, "Transmission Upgrades and Additions in West Texas," workshop presentation in PUC Project No. 25819, July 24, 2002.

difficult because (a) there is no commonly agreed-upon amount of wind power capacity that should be accommodated, and (b) there is no objective methodology for identifying areas with the best economic potential.

In 2003, the Texas Legislature expanded the Commission's authority to order new transmission to facilitate the development of renewable power. In exercising this authority, the Commission must take into account two major cost considerations. First, the expense of building new transmission will ultimately be uplifted to all ERCOT rate payers as non-bypassable transmission costs. Second, new transmission would require new rights of way from land owners in West Texas. Staff is currently examining options under existing legislation and whether additional authorization would be needed.

Under ERCOT market rules, wind farms that were instructed by system operators to curtail output because of transmission limitations were compensated for the power not generated. In addition, ERCOT stakeholders agreed to compensate wind farms for the value of lost tax credits and renewable energy credits, both of which normally accumulate value on the basis of actual output. The total compensation for lost credits is capped at $10 million and will be distributed to wind farm operators that file claims with ERCOT. The costs of these payments are uplifted to all rate payers in the ERCOT power region.

In MOD's view, compensation for curtailment and lost credits contradicts the economic signals to develop new capacity in locations other than McCamey. For this reason, MOD supported Protocol changes at ERCOT that would have eliminated curtailment payments and directly assigned congestion rent to those who cause congestion. ERCOT stakeholders rejected a MOD proposal to establish a McCamey congestion management zone, but they did agree to develop a special congestion management regime for wind farms in the area in which curtailment payments are strictly limited and available transmission capacity is apportioned in a manner akin to water rights. MOD will monitor the results of the McCamey congestion management plan in 2003.

## J. Demand Resources

The ERCOT Protocols allow for loads to participate in the ERCOT administered markets as either Loads acting as Resources or Balancing Up Loads (BULs). LaaRs are loads that are qualified by ERCOT to bid capacity reserves in the Day-ahead ancillary services markets and can also bid blocks of energy in the balancing energy market. LaaRs must have telemetry and must be able to respond to ERCOT instructions. BULs are loads that are qualified to bid in the balancing energy market. Loads must have an Interval Data Recorder (IDR) meter to qualify as BULs but do not require telemetry. If struck, BULs received a capacity payment based on the MCPC in the Non-Spinning Reserve market in addition to an energy payment.

LaaRs started participating in the Responsive Reserves market in the Spring of 2002. By the end of 2002, 570 MW of load resources were actively bidding in that market, with over 300 MW more load resources in the process of being certified by ERCOT. Participation in the Non-Spinning Reserve and the Replacement Reserve markets has been technically possible since October 2002, however, loads have not yet been active in those markets. BULs participation will be technically possible as of June 2003.

While currently only large customers over 1 MW can participate in the ERCOT-run markets as LaaRs and BULs, small loads will also have an opportunity to participate in those markets when Direct Load Control (DLC) programs are in place. The first DLC program, which would provide up to 70 MW of load curtailment in the Houston Zone, is in place and ready to be implemented. However, delays in completing the necessary technical steps at ERCOT have pushed the implementation date to the summer of 2004.

The Demand Side Working Group (DSWG) is an ERCOT stakeholders committee that meets monthly to discuss issues related to load participation in the ERCOT markets. In 2002, the DSWG developed a document intended for potential interruptible customers that explains in simplified terms the provisions of the Protocols relating to load participation. In addition, the group identified a number of issues to be addressed through Protocol Revision Requests relating to LaaRs and BULs, and worked closely with ERCOT staff to resolve issues. Two important issues needing resolution are the determination of a baseline (i.e. a reference level against which to measure a load's consumption reduction) for loads participating in the ancillary services market, and the participation of loads in the RMR solution process as an alternative to generation. MOD Staff regularly attends the DSWG meetings and works in cooperation with the group to develop solutions that will facilitate load participation.

On March 15, 2002, MOD issued a Request for Proposals to several consulting companies to conduct a study of demand-side resources and price responsiveness in the ERCOT market. The purpose of this project was for the contracted consultant to review the existing programs and market rules, identify barriers to load participation, and make recommendations for modifications to rules and programs to facilitate the participation of load resources in the balancing energy market and the ancillary services markets. In May 2002, MOD retained a third party independent consultant, Laurits R.Christensen Associates, Inc., for this work. The consultants' short term recommendations included conducting a survey of previous interruptible customers, REPs, and QSEs to understand their perception of and motivating factors for load participation in the market, developing pilot curtailment programs especially in constrained areas such as the Dallas-Fort Worth area, and evaluating metering policies. Long term recommendations included the development of a centralized day-ahead electricity market and the adoption of efficient locational pricing of electrical energy.

In addition to these recommendations, MOD Staff suggested that a training program be developed by ERCOT, targeting large customers and REPs, in order to explain the intricacies of load participation in the ERCOT markets. MOD Staff also suggested that ERCOT hire a Demand-side expert to interface with QSEs representing load resources and with the DSWG. Both recommendations have been implemented. In addition, MOD Staff, in cooperation with the DSWG, started working on a survey of previous interruptible customers, which will be administered in 2003.

## K. Resource Expansion and Mothballed Units

Located entirely within the state of Texas, ERCOT is isolated from other regions in the Eastern and Western U.S. interconnected systems except for two DC Ties which have a combined capacity of 856 MW. Isolation means that ERCOT has complete control of its own system, but it also means that ERCOT must rely entirely on its own resources to meet customer demand. Fortunately, more than 19,000 MW of new generating capacity was built in ERCOT between 1995 and the end of 2002. In addition, there was another 5,800 MW of capacity under construction at the end of 2002. However, like most regions, ERCOT has experienced deferrals and cancellations of plant construction. Eleven projects totaling more than 7,300 MW were cancelled in the last two years. A summary of new generation at the end of 2002 is shown in Table 19. A complete list of new generating plants including plant names, developers, locations, and capacities is shown in Appendix 1.

**Table 19: New Generation Capacity by Actual or Projected Completion Date**

| | 1996-2000 | 2001 | 2002 | 2003 | 2004 | 2005-2007 | Total |
|---|---|---|---|---|---|---|---|
| Completed Projects (MW) | 6,684 | 5,893 | 6,596 | | | | 19,173 |
| Projects Under Construction (MW) | | | 23 | 3,972 | 1,808 | | 5,803 |
| Announced Projects (MW) | | | | 160 | 845 | 5,965 | 6,970 |

ERCOT Peak demand was 54,862 MW in 2001 and 56,233 MW in 2002. The 2002 peak represented a 2.5 percent growth in demand over the previous year, but the 2001 peak was 4.8 percent below the all-time peak demand of 57,606 MW which occurred in 2000. ERCOT's most recent five-year projections for capacity, demand, and reserve margin (May 2003) are shown in Table 20. MOD does not entirely agree with the capacity projections; however, it is likely that there will be ample reserve margins in ERCOT for several years to come.[60]

**Table 20: Projected ERCOT Reserve Margins**

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|
| Capacity (MW) | 78,715 | 83,206 | 83,523 | 85,892 | 85,892 | 85,892 |
| Firm Demand (MW) | 56,925 | 58,366 | 59,843 | 61,357 | 62,908 | 64,499 |
| Reserve Margin (%) | 38.3% | 42.6% | 39.6% | 40.0% | 36.5% | 33.2% |

One category of the new generation capacity presents a unique challenge from the standpoint of long-term planning. "Switchable" plants are plants that can switch the interconnection of their individual units, typically in many combinations, back and forth between ERCOT and another reliability council. There are now two such plants in ERCOT: (1) Tenaska Gateway (845 MW) – switchable with the Southwest Power Pool (SPP) and (2) Tenaska Frontier (830 MW) – switchable with the Southeastern Electric Reliability Council (SERC). Going forward, it will be difficult to project how much capacity will be available in ERCOT from these plants because their capacity may not be committed to one region or another through long-term contracts, and even if it is, the owners are not required to file such information with ERCOT or the Commission. Some market participants have argued that there is diversity between ERCOT and other regions, and therefore switchable capacity will be made available to the region with the

[60] MOD's reservations concerning the capacity projections were presented in the Commission's Open Meeting on June 18, 2003 in Project No. 24255. If it is assumed that only 50% of switchable capacity, DC Ties, LaaRs, and none of the recently mothballed capacity would be available, the reserve margins would range from about 33% in 2004 to about 23% in 2008. Future announcements of additional mothballed or retired units would lower the reserve margins even further.

highest demand/prices. However, no data has been provided that would allow quantification or even estimation of the effects of diversity and relative price on availability. The challenge presented by switchable capacity will only increase since Tenaska has another 1,220 MW of switchable capacity coming line in 2003, and other developers have announced plans for three switchable plants totaling 2,150 MW.

ERCOT is becoming more dependent on natural gas since virtually all of the new generating capacity, except for wind and other renewable resources, is gas fired. This dependence is made more critical by the fact that most of the new generation does not have dual fuel capability because the developers determined that it was not economic to include it. The generation mix at the end of 2002 is shown in Table 21.

**Table 21: Generating Capacity by Energy Source in 2003[61]**

| | Natural Gas | Coal | Nuclear | Wind | Hydro | Other | Total |
|---|---|---|---|---|---|---|---|
| Capacity (MW) | 59,147 | 15,133 | 4,737 | 941 | 552 | 412 | 80,922 |
| Percent of Total | 73.1% | 18.7% | 5.9% | 1.2% | 0.7% | 0.5% | 100% |

More than 30% of ERCOT generation is more than 30 years old. Some units have been upgraded to improve their efficiency, but others have not. In 2002 both American Electric Power (AEP) and Reliant Resources (Reliant) announced that some of their older, gas-fired units would be mothballed. ERCOT evaluated each of the proposed mothball units to determine whether they were needed for reliability purposes, and it concluded that some of the AEP units were needed for the last quarter of 2002 (see Section IV.L of this report). ERCOT reevaluates the reliability need for such plants every quarter. Table 22 provides a list of the mothballed units.

Like switchable capacity, mothballed capacity also presents a challenge for long-term planning. Presumably, a mothballed plant could be brought back into service if economically justified, but the return-to-service decision will depend on a variety of economic criteria which will be established by the plant owner. Predicting such decisions will be difficult due to the lack of available data and the fact that there is no unique definition of what it means to “mothball” a unit. The cost and time required to bring mothballed units back to service can be highly variable depending on what measures were taken to mothball the unit. It should also be recognized that the plant owner may have an incentive to leave the plant in mothball status if doing so would increase the value of the owner’s other plants and discourage the construction of new generation. Therefore, it could be argued that mothballed capacity should be excluded from reserve margin projections, but if the Commission implements some sort of capacity market through a reserve margin requirement, the announcement of mothballed or retired units could be subject to gaming as a means to increase capacity payments. On the other hand, if mothballed capacity is included in projected reserve margins, it could lead to overestimation of the capacity that will truly be available.

[61] The 2003 value for capacity includes mothballed capacity which is not reflected in the reserve margin calculation in Table 20.

**Table 22: Capacity Mothballed in 2002**

| Company | Plant | County | Zone | Units | Summer Capacity (MW) |
|---|---|---|---|---|---|
| AEP/CPL | E.S. Joslin | Calhoun | South | 1 | 254 |
| AEP/CPL | Lon C. Hill | Nueces | South | 1,2,3,4 | 559 |
| AEP/CPL | Nueces Bay | Nueces | South | 5,6,7 | 560 |
| AEP/CPL | Victoria | Victoria | South | 4,5,6 | 491 |
| AEP/WTU | Abilene | Taylor | West | 4 | 18 |
| AEP/WTU | Fort Phantom | Jones | West | 1 | 158 |
| AEP/WTU | Fort Stockton | Pecos | West | 2 | 5 |
| AEP/WTU | Lake Pauline | Hardeman | West | 1,2 | 35 |
| AEP/WTU | Oak Creek | Coke | West | 1 | 85 |
| AEP/WTU | Paint Creek | Haskell | West | 1,2,3,4 | 217 |
| AEP/WTU | Rio Pecos | Crockett | West | 5 | 38 |
| | | **Subtotal** | | | **2,420** |
| | | | | | |
| Reliant | Deepwater | Harris | Houston | 7 | 174 |
| Reliant | Greens Bayou | Harris | Houston | 5 | 406 |
| Reliant | P.H. Robinson | Galveston | Houston | 1,2,3,4 | 2213 |
| Reliant | T.H. Wharton | Harris | Houston | 2 | 229 |
| Reliant | Webster | Harris | Houston | 3 | 374 |
| | | **Subtotal** | | | **3,396** |
| | | | | | |
| | | **Total** | | | **5,816** |

## L. RMR Contracts in ERCOT

Prior October of 2002, no RMR contracts were present in ERCOT. On Sept 11, 2002, AEP announced their intention to mothball all of their gas fired plants in ERCOT, sixteen plants in total, with a total generating capacity of 3,866 megawatts. AEP noted that "...we are buying power for a price below the production costs of 16 of our gas-fired plants. The plants have been idle for much of the year, except when called on by ERCOT for reliability purposes."[62]

Seven of the AEP plants (15 units in all) were contracted to provide RMR service for October – December 2002. One unit at the Frontera plant in the Rio Grand Valley was also contracted to provide RMR service. These contracts provided ERCOT with a total of 1868 MW of capacity was available for use in voltage support, stability or management of localized transmission constraints. The following table details the units under RMR contracts.

[62] AEP Press Release

**Table 23: RMR Units During Fourth Quarter of 2002**

| Local Area | Zone | Station Name | Unit | Contracted Capacity (MW) |
|---|---|---|---|---|
| Corpus Christi | South | B.M. Davis | B_DAVIS_B_DAVIG1 | 335 |
| Corpus Christi | South | B.M. Davis | B_DAVIS_B_DAVIG2 | 356 |
| Laredo | South | Laredo | LAREDO_LAREDOG1 | 35 |
| Laredo | South | Laredo | LAREDO_LAREDOG2 | 32 |
| Laredo | South | Laredo | LAREDO_LAREDOG3 | 105 |
| Valley | South | Bates | BATES_BATES_G1 | 74 |
| Valley | South | Bates | BATES_BATES_G2 | 109 |
| Valley | South | Frontera | FRONTERA_FRONTEG1 | 150 |
| Valley | South | La Palma | LA_PALMA_LA_PALG4 | 23 |
| Valley | South | La Palma | LA_PALMA_LA_PALG5 | 23 |
| Valley | South | La Palma | LA_PALMA_LA_PALG6 | 153 |
| Valley | South | La Palma | LA_PALMA_LA_PALG7 | 50 |
| Abilene Area | West | Fort Phantom | FTPP_FTPP_G2 | 202 |
| West | West | Rio Pecos | RIOP_RIOP_G6 | 98 |
| West | West | San Angelo | SAPS_SAPS_G1 | 21 |
| West | West | San Angelo | SAPS_SAPS_G2 | 102 |
| | | | **Total** | **1,868** |

The cost to the ERCOT market of RMR Service in the last quarter of 2002 was $32 million. The costs were about equally divided between the three months and they are shown by local area in Table 24. Net cost to ERCOT is calculated as follows Net Cost = (Capacity Payments (Standby Price) + Energy Payments + Start Up Payments) – BENA credit. BENA credit is the value of energy provided which otherwise would have to be purchased from the balancing energy market at MCPE.

**Table 24: RMR Net Costs by Local Area (Million $)[63]**

| Local Area | Zone | Net Costs |
|---|---|---|
| Corpus Christi | South | $9.8 |
| Laredo | South | $4.0 |
| Valley | South | $11.5 |
| Abilene Area | West | $3.2 |
| West (Rio Pecos & San Angelo) | West | $3.6 |
| | **Total** | $32.0 |

### 1. RMR Payment Components per ERCOT Protocols

Units contracted to provide RMR service to ERCOT are compensated for Start-up Costs, Energy Costs, and are also paid a Standby Price. The Protocols also allow an RMR unit owner to retain 90% of the gross revenues from energy generated in excess of the amount that the unit is

[63] Current as of Final Settlements.

obligated to produce under its RMR contract, or receive 10% of positive margins for energy generated in excess of the amount that the unit is obligated to produce under its RMR contract.

- The Standby Price is based on the levelized annual carrying costs of a then current simple-cycle gas turbine generator set – sized to match the RMR unit.
- The Energy Payment is based on the average of last two years of actual heat rate data, a Published Gas Index per the RMR Agreement, Transportation fee, and Gas swing service fee, plus a non-fuel Variable Cost component.
- Start-up costs are as per the RMR Agreement.

RMR costs are allocated to QSEs on a Load Ratio Share basis.

### 2. RMR Task Force Formed

After the significant costs for RMR began to be incurred, ERCOT stakeholders formed a task force to study the issue of RMR. Some stakeholders perceive that the payments for OOM and RMR are overly generous and therefore create incentives to not participate in the market. An additional motivation for the task force was the related issue of payment for OOM and an appeal of certain OOM payment Protocols by Frontera.

The stated objectives of the RMR Task Force are to:

- Review existing OOM and RMR protocol requirements/compensation
- Determine issues that need to be addressed
- Evaluate alternatives to existing OOM and RMR Protocols
- Make recommendations for Protocol Revisions to appropriate committees

The Task Force is currently working through these specific issues:

- How to treat the Economic Trade Offs of RMR vs. OOM?
- Are changes needed in the Transmission Planning Process?
- How to allocate costs of RMR?
- What should be the criteria for RMR Units?
- Should there be additional RMR Categories, such as partial year contracts?
- Should compensation be based on a proxy or actual costs?

## M. Resource Adequacy

Under regulation, electric utilities in Texas were required to maintain a 15% planning reserve margin, but in a competitive market no specific level of reserve capacity is assured. Therefore, in approving the ERCOT Protocols[64] the Commission said it would address fundamental policy options to determine whether the adequacy of reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin and, if so, what

[64] *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, Docket No. 23220, Order on Rehearing, June 4, 2001.

means should be used. The Commission subsequently determined that a rulemaking process should be initiated to establish a minimum planning reserve margin level for ERCOT and a mechanism for maintaining that level.

In January 2002, in Project No. 24255, MOD Staff issued a request for comments from market participants on the appropriate reserve margin level for ERCOT and the best reserve margin mechanism that could be used to maintain it.[65] In February and April, MOD held workshops in which various parties presented their respective recommendations for the most appropriate reserve margin mechanism.[66] Parties who recommended reserve margin mechanisms were:

- Alliance for Retail Markets (ARM)
- American National Power (ANP) – modified NEPOOL ICAP
- Lower Colorado River Authority (LCRA) – Mechanism to Ensure Capacity Adequacy (MECA)
- Reliant Resources – Regional Reliability Commitment (RRC)
- Shmuel Oren (Commission Consultant) – Call Option
- Strategic Energy – modified ACAP
- TXU – Reserve Margin Response Cap (RMRC)

Participants in the April workshop also discussed three threshold issues that had emerged after the February workshop. The threshold issues were:

1. Should there be mandatory centralized acquisition of reserve resources by ERCOT or should the acquisition of reserve resources be the responsibility of individual load serving entities (LSEs)? If a mandatory centralized approach is selected, should it allow for self-provision and self arrangement?

2. Should the acquisition of reserve capacity include payments to existing resources and new resources or only to new resources?

3. Should the reserve margin mechanism operate continuously after the trigger point is reached, or should it be implemented for a specified period of time with periodic reassessment of the conditions that would trigger implementation again?

Based on discussion of the threshold issues, MOD Staff recommended to the Commission that LSEs should be able to meet their reserve obligation through self-arrangement or a centralized auction operated by ERCOT. The primary benefit of a centralized auction is that it could be structured so that LSEs would be able to pay for reserve capacity after-the-fact based on actual rather than projected load ratio shares. On the second issue, some parties argued that new resources could receive capacity payments as an incentive for construction, but that existing resources were not entitled to payments for capacity that was already in existence. However, MOD recommended that all resources that provide reserve capacity should be compensated,

[65] *Rulemaking Concerning Planning Reserve Margin Requirements*, Project No. 24255, Staff Request for Comments (January 29, 2002).

[66] Discussion of the appropriate level for the reserve margin in percentage terms was deferred while ERCOT evaluated the results of a technical consulting study on generation adequacy.

regardless of whether they are new or existing resources. On the third issues, MOD agreed with the position of most parties that it was better to implement the reserve margin mechanism on a continuous operation basis rather than turn it on and off from year to year. This would provide stability and predictability that would allow ERCOT to acquire capacity when prices are low and allow parties to take account of the process when they adjust their respective portfolios of bilateral contracts. After discussion in an Open Meeting, the Commission approved MOD's recommendations.

Market participants also evaluated the various reserve margin mechanisms through the ERCOT Generation Adequacy Work Group (GAWG). At the conclusion of its process, the GAWG prepared a report that recommended the RRC model as proposed by Reliant Resources. The report highlighted the differences between the RRC model and the MECA model proposed by LCRA. Both mechanisms employed a centralized auction conducted by ERCOT, but in the RRC model the auction quantity would be equal to the projected peak demand plus the required reserve capacity, while in the MECA model the auction quantity would be equal to the projected peak demand plus the required reserve capacity *minus* the projected installed capacity. Other key differences were: (1) the auction clearing price in RRC could be set by any resource, but in MECA it could be set only by new generation; (2) the auction product under RRC was one year, but under MECA it was five years; and (3) RRC limited the number of hours ERCOT could call on a resource, but MECA provided ERCOT with a call on the resources for all available hours. The GAWG report was adopted by the Wholesale Market Subcommittee (WMS) committee and passed on to the Technical Advisory Committee (TAC), but it was not adopted by TAC.

Also at ERCOT, the Board of Directors adopted a 12.5% reserve margin. This level was based on the results of a Loss of Load Probability (LOLP) study that was conducted for ERCOT by an outside consultant.[67] The next generation adequacy study was scheduled to be completed by January 2004.

MOD Staff developed a strawman for the Substantive Rule on reserve margin and held a workshop in December for discussion with stake holders. The strawman was based on the RRC model with several modifications. Key aspects of the strawman were:

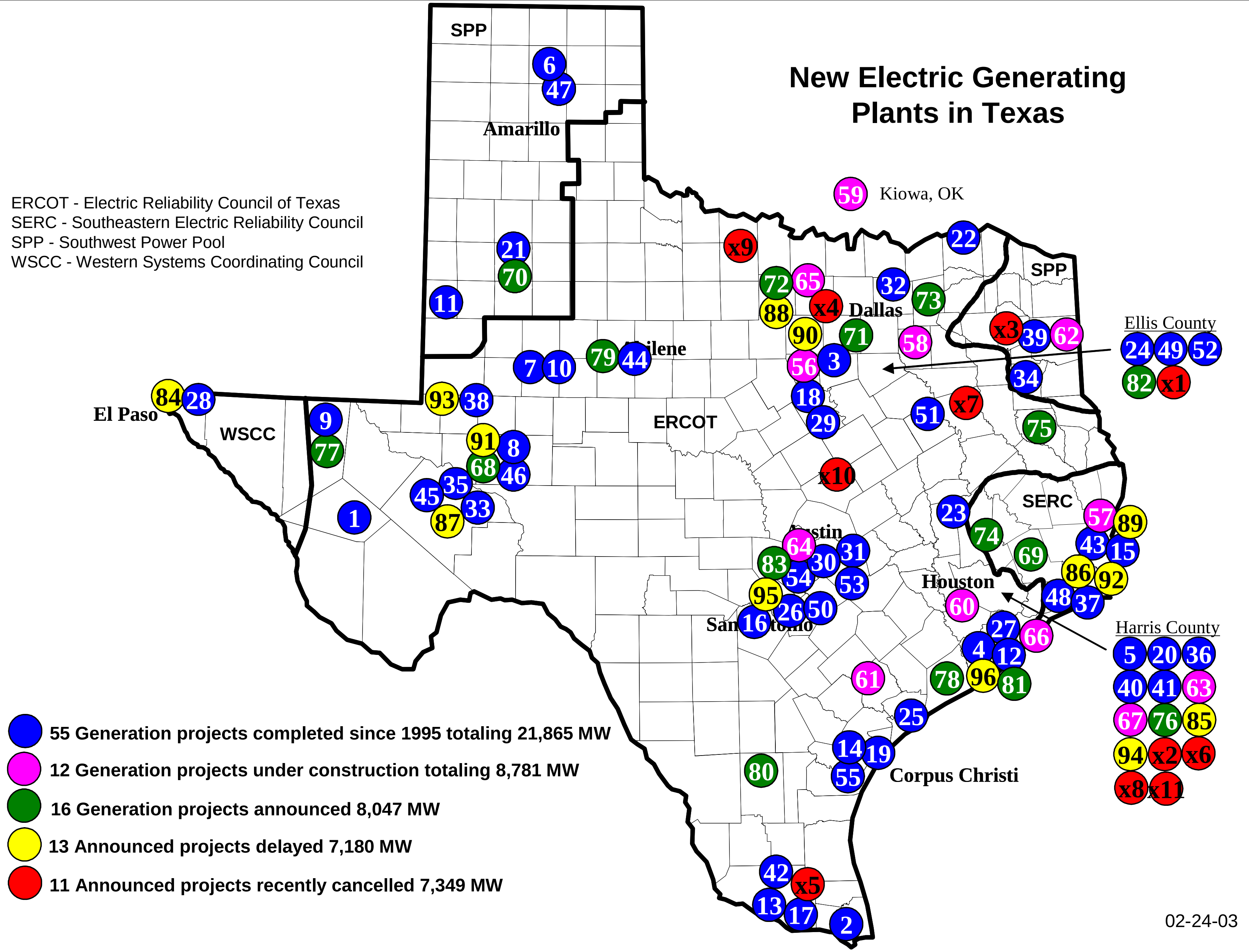
- Independent five-year forecast prepared by ERCOT
- Reserve margin mechanism triggered when projected capacity in third forward year is less than projected demand plus reserve margin
- LSEs can meet reserve requirement via self-arrangement or centralized auction or combination
- ERCOT would conduct centralized auction to obtain call options on capacity in third forward year equal to projected load plus required reserve capacity
- Auction clearing price can be set by existing or new resources or load resources
- Auction costs allocated to months based on LOLP and then allocated to LSEs based on after-the-fact, actual load ratio share
- Resources unavailable for more than one day in a month would not receive capacity payments for the month

[67] The reserve margin level ultimately adopted in the Commission's Substantive Rule on reserve margins may or may not be the same as the level determined by the ERCOT Board.

- When available, resources must offer bid into ancillary service or balancing energy market

Much of the workshop discussion focused on the need for physical self-arrangement, the need for a call option on capacity, the impact of high availability requirements, and the potential for higher costs as a result of the auction. Based on the discussion MOD tentatively decided to eliminate the physical self-arrangement option, although it still may be needed by electric cooperatives in order to preserve their status as not-for-profit entities. MOD distributed a revised strawman in early 2003 and solicited additional written comments. Debate on reserve margin issues is continuing.

# New Electric Generating Plants in Texas



# Generation Projects Completed in Texas Since 1995[68]

| Map No. | Company | Facility | City (County) | Capacity[69] (MW) | Cogen Host (MW) | Date in Service | Intercon-nection | Region |
|---|---|---|---|---|---|---|---|---|
| 1 | CSW Services (wind) | | Ft. Davis (Jeff Davis) | 6.6 | | Jan-96 | WTU | ERCOT |
| 2 | City of Brownsville | Silas Ray | Brownsville (Cameron) | 43 | | Jun-96 | BPUB | ERCOT |
| 3 | Tenaska IV Texas Partners | Tenaska IV Texas Partners | Cleburne (Johnson) | 258 | | Nov-96 | TU/BEPC | ERCOT |
| 4 | CSW Energy | Sweeny Cogeneration | Sweeny (Brazoria) | 330 | 90 | Feb-98 | TNMP | ERCOT |
| 5 | Calpine/Phillips | Pasadena Power Plant I | Pasadena (Harris) | 240 | 90 | Jul-98 | Reliant | ERCOT |
| 6 | Borger Energy Associates | Black Hawk Station | Borger (Hutchinson) | 254[70] | 38 | Aug-98 | SPS | SPP |
| 7 | York Research (wind) | Big Spring Wind Power | Big Spring (Howard) | 34 | | Feb-99 | TU | ERCOT |
| 8 | FPL Energy (wind) | Southwest Mesa Wind Proj. | McCamey (Upton) | 75 | | Jun-99 | WTU | ERCOT |
| 9 | American National Wind Power (wind) | Delaware Mtn Wind Farm | Delaware Mtn (Culberson) | 30 | | Jun-99 | TXU | ERCOT |
| 10 | York Research (wind) | Big Spring Wind Power | Big Spring (Howard) | 6.6 | | Jun-99 | TXU | ERCOT |
| 11 | Golden Spread/LS Power | Mustang Station | Denver City (Yoakum) | 280<br>198 | | Jun-99<br>May-00 | SPS | SPP |
| 12 | BASF | Freeport | Freeport (Brazoria) | 93 | | Jul-99 | Reliant | ERCOT |
| 13 | CSW Energy | Frontera Power Station | Mission (Hidalgo) | 344<br>170 | | Jul-99<br>May-00 | CPL | ERCOT |
| 14 | Conoco Global-OxyChem | Ingleside Cogeneration | Ingleside (San Patricio) | 440 | 235 | Oct-99 | CPL | ERCOT |
| 15 | Reliant Energy/Air Liquide/Bayer | Sabine Project | Sabine (Orange) | 100 | 36 | Dec-99 | Entergy | SERC |
| 16 | CPS | A. von Rosenberg | San Antonio (Bexar) | 500 | | May-00 | CPS | ERCOT |
| 17 | Calpine | Hidalgo Energy Center | Edinburg (Hidalgo) | 500 | | Jun-00 | CSW | ERCOT |
| 18 | Southern Energy | Bosque County Power Plant | Lake Whitney (Bosque) | 308 | | Jun-00 | Brazos | ERCOT |
| 19 | LG&E/Columbia-Reynolds | Gregory Power Plant | Gregory (San Patricio) | 450 | 50 | Jul-00 | CSW | ERCOT |
| 20 | Calpine | Pasadena Power Plant II | Pasadena (Harris) | 540 | | Jul-00 | Reliant | ERCOT |
| 21 | Lubbock Power & Light | J. Robert Massengale | Lubbock (Lubbock) | 43 | | Sep-00 | LPL | SPP |
| 22 | FPL Energy/Panda Energy | Lamar Power Plant | Paris (Lamar) | 1000 | | Sep-00 | TXU | ERCOT |
| 23 | Tenaska/PECO Power Team | Tenaska Frontier Gen. Sta. | Shirow (Grimes) | 830 | | Sep-00 | Reliant/EGS | ERCOT/SERC |
| 24 | ANP | Midlothian I | Midlothian (Ellis) | 820<br>280 | | Oct-00<br>Feb-01 | TXU | ERCOT |

68 The Texas Legislature opened the electric wholesale market in Texas to competition on September 1, 1995.
69 Wind generation facilities are shown at nameplate capacity rating; however, the actual capacity they provide at the time of peak demand may be substantially less.
70 Approximately 216 MW is under 25-year contract to SPS.

## Generation Projects Completed in Texas Since 1995 (continued)

| Map No. | Company | Facility | City (County) | Capacity (MW) | Cogen Host (MW) | Date in Service | Intercon-nection | Region |
|---|---|---|---|---|---|---|---|---|
| 25 | Union Carbide | | Seadrift (Calhoun) | 40 | 40 | Nov-00 | CPL | ERCOT |
| 26 | Texas Independent Energy | Guadalupe Power Plant | Marion (Guadalupe) | 1000 | | Jan-01 | LCRA | ERCOT |
| 27 | AEP-Phillips | Sweeny (expansion) | Sweeny (Brazoria) | 110 | 35 | Jan-01 | TNMP | ERCOT |
| 28 | Cielo/El Paso Electric (wind) | Hueco Mountain Wind Ranch | Hueco Mtn. (El Paso) | 1.3 | | Apr-01 | EPE | WSCC |
| 29 | Mirant | Bosque County Power Plant | Lake Whitney (Bosque) | 248 | | Jun-01 | Brazos | ERCOT |
| 30 | Enron/Austin | Sand Hill Energy Center | Austin (Travis) | 180 | | Jun-01 | AE | ERCOT |
| 31 | Calpine/Gen Tex Power | Lost Pines I | Lost Pines (Bastrop) | 520[71] | | Jun-01 | LCRA/AE | ERCOT |
| 32 | Garland Power & Light | Ray Olinger Power Plant | Garland (Collin) | 75 | | Jun-01 | GP&L | ERCOT |
| 33 | Orion Energy/Amer Nat Wind Pwr (wind) | Indian Mesa I | (Pecos) | 82.5 | | Jun-01 | WTU | ERCOT |
| 34 | Tenaska/Coral Energy | Tenaska Gateway Gen. Sta. | Henderson (Rusk) | 845 | | Jul-01 | TXU/AEP | ERCOT/SERC |
| 35 | FPL/Cielo/TXU (wind) | Woodward Mountain Ranch | McCamey (Pecos) | 160 | | Jul-01 | WTU | ERCOT |
| 36 | Calpine-Lyondell-Citgo | Channel Energy Center | Houston | 160<br>400 | 160 | Jul-01<br>Apr-02 | Reliant | ERCOT |
| 37 | Fina BASF | | Port Arthur (Jefferson) | 80 | 80 | Aug-01 | EGS | SERC |
| 38 | Texas Independent Energy | Odessa-Ector Power Plant | Odessa (Ector) | 1000 | | Aug-01 | TXU | ERCOT |
| 39 | AEP/Eastman Chemical | | Longview (Harrison) | 440 | 130 | Aug-01 | SWEPCO | SPP |
| 40 | Exelon/Air Products & Chemicals | ExTex Power Station | La Porte (Harris) | 165 | | Aug-01 | Reliant | ERCOT |
| 41 | Reliant Energy / Equistar | Reliant Energy Channelview | Channelview (Harris) | 172<br>608 | 293 | Aug-01<br>Jun-02 | Reliant | ERCOT |
| 42 | Calpine | Magic Valley Gen. Station | Edinburg (Hidalgo) | 350[72]<br>380 | | Sep-01<br>Dec-01 | CPL | ERCOT |
| 43 | Conoco Global/Dupont | SRW Cogeneration | Orange (Orange) | 420[73] | 70 | Nov-01 | EGS | SERC |
| 44 | AEP (wind) | Trent Mesa | Trent Mesa (Nolan) | 150 | | Nov-01 | TXU | ERCOT |
| 45 | AEP (wind) | Desert Sky (Indian Mesa II) | Iraan (Pecos) | 160 | | Dec-01 | WTU | ERCOT |
| 46 | FPL/Cielo (wind) | King Mtn Wind Ranch | McCamey (Upton) | 278 | | Dec-01 | WTU | ERCOT |
| 47 | Shell Wind Energy (wind) | Llano Estacado Wind Ranch | White Deer (Carson) | 79 | | Jan-02 | SPS | SPP |
| 48 | Calpine-Bayer | Baytown Power Plant | Baytown (Chambers) | 700 | 300 | Apr-02 | Reliant | ERCOT |
| 49 | Tractebel | Ennis Tractebel Power Proj. | Ennis (Ellis) | 343 | | Jun-02 | TXU | ERCOT |

[71] GenTex is an affiliate of LCRA. Half of plant capacity will serve LCRA; Calpine will sell the remainder.
[72] Magic Valley Electric Cooperative has contracted to buy 246 MW for 2001, increasing by 25 MW in 2002.
[73] PG&E Energy Trading will take up to 250 MW over a 10-year period. Approximately 100 MW will be sold into the SERC region.

## Generation Projects Completed in Texas Since 1995 (continued)

| Map No. | Company | Facility | City (County) | Capacity (MW) | Cogen Host (MW) | Date in Service | Intercon-nection | Region |
|---|---|---|---|---|---|---|---|---|
| 50 | Constellation Power | Rio Nogales Power Plant | Seguin (Guadalupe) | 800 | | Jun-02 | LCRA | ERCOT |
| 51 | Calpine | Freestone Energy Center | Fairfield (Freestone) | 1040 | | Jul-02 | TXU | ERCOT |
| 52 | ANP | Midlothian II | Midlothian (Ellis) | 550 | | Aug-02 | TXU | ERCOT |
| 53 | FPL Energy/Coastal Power | Bastrop Energy Center | (Bastrop) | 535 | | Aug-02 | AE/LCRA | ERCOT |
| 54 | ANP | Hays Station | San Marcos (Hays) | 550<br>550 | | Apr-02<br>Aug-02 | LCRA | ERCOT |
| 55 | Calpine-Citgo | Corpus Christi Energy Center | Corpus Christi (Nueces) | 520 | 60 | Oct-02 | AEP-CPL | ERCOT |
| | ***55 Projects Completed*** | | ***Total Capacity*** | ***21,865*** | ***1,747*** | | | |

## Generation Projects Under Construction in Texas

| Map No. | Company | Facility | City (County) | Capacity (MW) | Cogen Host (MW) | Date in Service | Intercon-nection | Region |
|---|---|---|---|---|---|---|---|---|
| 56 | AES[74] | Wolf Hollow Power Plant | Granbury (Hood) | 730 | | Mar-03 | TXU | ERCOT |
| 57 | InterGen | Cottonwood Energy Project | Deweyville (Newton) | 1200 | | Apr-03 | EGS | SERC |
| 58 | FPL/Cobisa | Forney | Forney (Kaufman) | 1789 | | Apr-03 | TXU | ERCOT |
| 59 | Tenaska[75] | Kiamichi Generating Station | Kiowa, OK | 1220 | | Apr-03 | TXU | SPP/ERCOT |
| 60 | NRG Energy | Brazos Valley Energy | Thompsons (Fort Bend) | 633 | | May-03 | Reliant | ERCOT |
| 61 | South Texas Electric Co-op | | Nursery (Victoria) | 185 | | Jun-03 | STEC | ERCOT |
| 62 | Entergy/NTEC[76] | Harrison County Gen Station | (Harrison) | 550 | | Jun-03 | SWEPCO | SPP |
| 63 | Calpine-Shell | Deer Park Energy Center | Deer Park (Harris) | 335 | 190 | Aug-03 | Reliant | ERCOT |
| | | | | 438 | | Jun-04 | | |
| 64 | Austin Energy | Sand Hill P1 | Del Valle (Travis) | 300 | | Oct-03 | AE | ERCOT |
| 65 | Tractebel | Wise County Power Project | Bridgeport (Wise) | 800 | | Jan-04 | TXU | ERCOT |
| 66 | BP/Cinergy | Texas City | Texas City (Galveston) | 570 | NA | Feb-04 | TNMP | ERCOT |
| 67 | Reliant/Jenbacher[77] | | Houston (Harris) | 23 | | Dec-02 | Reliant | ERCOT |
| | | | Conroe (Montgomery) | 8 | | Feb-03 | EGS | SERC |
| | ***12 Projects Under Construction*** | | ***Total Capacity*** | ***8,781*** | | | | |

[74] Twenty-year agreement to sell 350 MW to Excelon Energy Company, and the balance will be marketed by affiliate AES NewEnergy.
[75] Plant is under construction in Oklahoma, however the output will be switchable between SPP and ERCOT.
[76] Project is 70% owned by Entergy and 30% owned by Northeast Texas Electric Cooperative.
[77] Project currently consists of six landfill gas generation sites. Several smaller sites @ 2 MW could be developed in the future.

## Announced Generation Projects in Texas

| Map No. | Company | Facility | City (County) | Capacity (MW) | Expected Construction Date | Expected Date In Service | Region |
|---|---|---|---|---|---|---|---|
| 68 | TXU Energy/Cielo Wind (wind) | Noelke Hill Wind Ranch P1 | McCamey (Upton) | 160 | Mar-03 | Nov-03 | ERCOT |
| 69 | Sempra Energy Resources | Cedar Power Project | Dayton (Liberty) | 600 | Spring-03 | Spring-05 | ERCOT/SERC |
| 70 | Cielo Wind Power/LPL (wind) | Llano Estacado at Lubbock | Lubbock (Lubbock) | 2 | Jun-03 | Jun-03 | SPP |
| 71 | DFW Airport | | (Tarrant/Dallas) | 55<br>55 | 2003<br>2005 | 2005<br>2007 | ERCOT |
| 72 | Brazos EPC | Jack County Project | (Jack) | 600 | Jan-04 | Jan-06 | ERCOT |
| 73 | Cobisa | Greenville | Greenville (Hunt) | 1750 | Spring-04 | Spring-06 | ERCOT |
| 74 | Sempra Energy Resources | MC Energy Partners | Dobbin (Montgomery) | 600 | Apr-04 | Apr-06 | ERCOT/SERC |
| 75 | Steag Power | Sterne | Sacul (Nacogdoches) | 950 | 2Q-04 | 2Q-06 | ERCOT/SPP |
| 76 | Texas Petrochemicals | | Houston (Harris) | 900 | 2004 | 2006 | ERCOT |
| 77 | Orion Energy (wind) | | (Culberson) | 175 | NA | Jul-04 | ERCOT |
| 78 | Ridge Energy Storage[78] | Markham Energy Storage Center | (Matagorda) | 270 | NA | Dec-04 | ERCOT |
| 79 | GE Power Systems (wind)[79] | | Sweetwater (Nolan) | 400 | NA | 2004 | ERCOT |
| 80 | CCNG Inc[80] | | San Diego (Duval) | 310 | NA | 2Q-05 | ERCOT |
| 81 | Dow Chemical | | Freeport (Brazoria) | 170 | NA | Dec-05 | ERCOT |
| 82 | Tractebel | Ennis-Tractebel II | Ennis (Ellis) | 800 | NA | Jan-06 | ERCOT |
| 83 | Austin Energy | Sand Hill P2 | Del Valle (Travis) | 250 | NA | Sum-07 | ERCOT |
| | ***16 Projects Announced*** | | ***Total Capacity*** | ***8,047*** | | | |

[78] Compressed air energy storage project.
[79] Previous Enron Wind project being developed by GE Power Systems.
[80] Compressed air energy storage project which will require 60 to 70 miles of new transmission.

## Delayed Generation Projects[81]

| Map No. | Company | Facility | City (County) | Capacity (MW) | Expected Construction Date | Expected Date In Service | Region |
|---|---|---|---|---|---|---|---|
| 84 | ANP | | El Paso (El Paso) | 450 | NA | NA | WSCC |
| 85 | ANP | | Houston (Harris) | 2150 | NA | NA | ERCOT |
| 86 | Calpine | Amelia Energy Center | Beaumont (Jefferson) | 800 | NA | NA | SERC |
| 87 | Cielo | Capital Hill Wind Ranch | (Pecos) | 100 | NA | NA | ERCOT |
| 88 | Duke Energy[82] | Duke Energy Jack, LP | Jacksboro (Jack) | 650 | NA | NA | ERCOT |
| 89 | Hartburg Power | | Deweyville (Newton) | 800 | NA | NA | SERC |
| 90 | Mirant | | Weatherford (Parker) | 650 | NA | NA | ERCOT |
| 91 | TXU Energy/Cielo | Noelke Hill Wind Ranch P2 | McCamey (Upton) | 80 | NA | NA | ERCOT |
| 92 | Sabine Power I/Port of Port Arthur | | Port Arthur (Jefferson)[83] | 1000 | NA | NA | SERC |
| 93 | York Research Group (wind) | Notrees Wind Farm | (Ector, Winkler) | 80 | NA | NA | ERCOT |
| 94 | ExxonMobil[84] | | Baytown (Harris) | 170 | NA | NA | ERCOT |
| 95 | City Public Service[85] | | San Antonio (Bexar) | 180 | NA | NA | ERCOT |
| 96 | BP/Cinergy[86] | | Alvin (Brazoria) | 70 | NA | NA | ERCOT |
| | ***13 Projects Delayed*** | | ***Total Capacity*** | ***7,180*** | | | |

81 An announced project which does not have a projected in-service date is listed as delayed.
82 Filed air permit request on 9/25/02
83 Fuel for this plant would be provided by a petroleum coke gasification facility to be constructed in Port Arthur.
84 Filed air permit request on 10/4/02
85 Filed air permit request on 10/15/02
86 Recently reactivated, air permit request under review

## Cancelled Projects

| Map No. | Company | Facility | City (County) | Capacity (MW) | Year Cancelled | Region |
|---|---|---|---|---|---|---|
| X1 | Steag Power | | Ennis (Ellis) | 1200 | 2001 | ERCOT |
| X2 | KM Power | | (Harris) | 1070 | 2001 | ERCOT |
| X3 | Constellation Power | Gateway Power Project | Gilmer (Upshur) | 800 | 2001 | SPP |
| X4 | KM Power | | Boonville (Wise) | 510 | 2001 | ERCOT |
| X5 | ANP | | Edinburg (Hidalgo) | 550 | 2002 | ERCOT |
| X6 | Celanese | | Pasadena (Harris) | 284 | 2002 | ERCOT |
| X7 | Newport Generation | Palestine Power Project | Palestine (Anderson) | 1600 | 2002 | ERCOT |
| X8 | Dynegy[87] | Lyondell expansion | (Harris) | 155 | 2003 | ERCOT |
| X9 | Texas Independent Energy[88] | Archer Power Partners | Holliday (Archer) | 500 | 2003 | ERCOT |
| X10 | Duke Energy[89] | | (Bell) | 500 | 2003 | ERCOT |
| X11 | Calpine[90] | Channel Energy Center exp. | Houston (Harris) | 180 | 2003 | ERCOT |
| | ***11 Projects Cancelled*** | | ***Total Capacity*** | ***7,349*** | | |

[87] Air permit expired
[88] Air permit expired
[89] Air permit expired
[90] Air permit request withdrawn