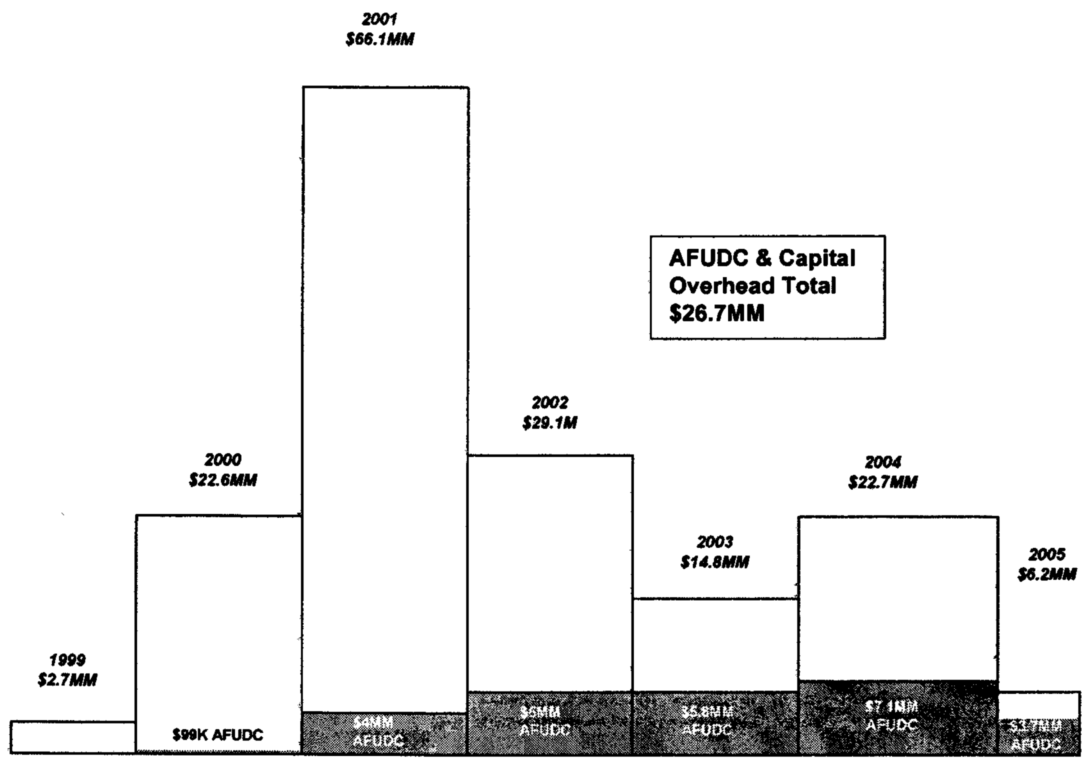
EGSI's TTC Costs By Year (in millions)								
	1999	2000	2001	2002	2003	2004	2005	Total
TTC Costs	2.73	22.58	66.09	29.12	14.84	22.66	6.21	164.24

Q. WHY IS THE SPENDING TREND FOR TTC SIGNIFICANT?

A. The spending trend is significant because it shows that changes in TTC costs mirror events with which the Commission is familiar. The Texas Legislature passed SB 7 in 1999. January 1, 2002 was the date that ROA was to commence in ESAT. The Commission first delayed the commencement of ROA in ESAT in late 2001. Accordingly, as can be seen from the timeline, the TTC costs increased dramatically over the period 1999 through 2001. This dramatic increase over that time frame is not surprising; it is consistent with the increase of activity that would be expected to meet the aggressive January 1, 2002 date for ROA commencement that was not initially delayed for ESAT until December of 2001.

Also not surprising is the decrease in TTC costs incurred in years after 2001 where the transition activities for EGSI were less extensive, but continued. Exhibit PRM-6 shows the Company's TTC cost trend by year, with a summary class of costs, and shows how costs were driven by regulatory requirements and market project timelines. The chart below, which is a simplified version of Exhibit PRM-6, shows the overall cost by year. It also shows the significant impact of extending the implementation of ROA beyond January 1, 2002 because, as shown, applicable AFUDC and Capital Overhead continue to accrue. I will discuss these cost trends in more detail below, including an explanation of why TTC costs increased from 2003 to 2004.

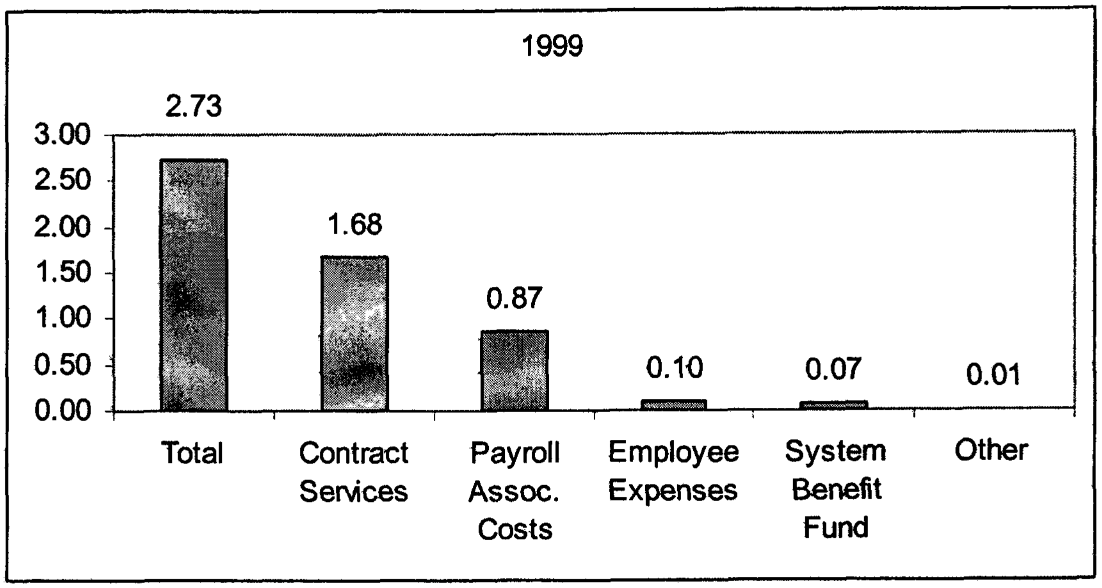
TTC Cost Trend Chart By Year (with AFUDC/Cap Overhead impact)



Q. DESCRIBE THE GENERAL AREAS OF TRANSITION COSTS THAT OCCURRED DURING 1999.

A. From June through December 1999, the Company incurred $2.7 million in TTC costs. These costs were primarily incurred while utilizing outside resources to assist with Texas and Texas-related regulatory filings, develop unbundling plans, and to assess the possible operational impacts of ROA. Included in this total is the Company's first payment to the System Benefit Fund of $73,263 and initial Energy Efficiency program costs of $16,000. The primary regulatory focus during this period was on the planning and preparation of the Company's January 10, 2000 Business Separation Plan, "BSP," and March 31, 2000 UCOS cases, as well as participating in or monitoring a growing number of Commission rulemaking projects related to ROA. In this time period, contract services accounted for a majority of the $1.7 of the $2.7 million total; outside legal costs of over $1.1 million made up most of the contract services. The majority of the remaining contract work amount was for business planning guidance related to unbundling, operations design and business case analysis. Payroll and associated costs (*e.g.,* payroll, payroll taxes, and benefits) accounted for only $868,000 of the total for that year; employee expenses (*e.g.,* travel and lodging) accounted for approximately $97,000. These 1999 costs are displayed graphically in the following bar chart.

TTC Cost in 1999 By Major Cost Type (in millions)



Q. DESCRIBE THE REGULATORY ACTIVITIES THAT OCCURRED DURING 1999.

A. In addition to the focus on the Company's UCOS and BSP filings, as is shown in Exhibit PRM-7, the Company also participated in or monitored 18 separate rulemaking projects during 1999. In response to these rulemakings, the Company selected jurisdictional leads to participate in the workshops, as necessary, or to monitor the specific project. The Company also selected jurisdictional leads to represent EGSI in the ERCOT collaborative rulemaking process. Jurisdictional leads were employees that were experts in the subject matter area being discussed at the collaborative and rulemaking sessions. The jurisdictional leads worked with the implementation teams to enlist appropriate resources from the key functional areas.

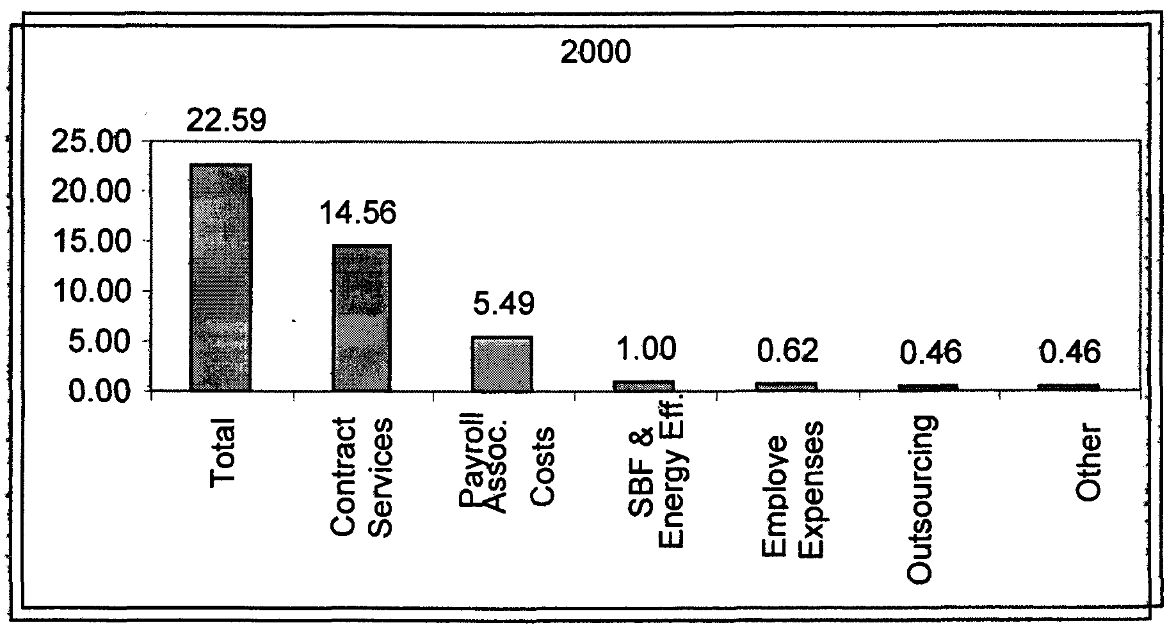
Q. DESCRIBE THE IMPLEMENTATION ACTIVITIES THAT OCCURRED DURING 1999.

A. The primary focus of implementation efforts during that period was to develop initial assessments and business/implementation planning stages for transition impacts to operations and the overall business. Neither Texas' nor Arkansas' market models were specified by the legislation. Instead, each jurisdiction was beginning to develop the high level market design before moving into the detailed market rules. The Company engaged experienced consultants and outside expertise to assist its own internal functional expertise in assessing the business requirements of various market models under development and the impact that such models might have on staffing, systems changes, costs and business processes.

Q. DESCRIBE THE GENERAL AREAS OF TRANSITION COSTS THAT OCCURRED DURING 2000.

A. The Company incurred $22.6 million in TTC costs in 2000. The Company was still immersed in the planning and early implementation phase. A significant portion of these costs were related to unbundling and separation activities, numerous rulemakings, stranded cost determination, and modification of the Entergy System Agreement. Included in this total is the Company's second payment to the System Benefit Fund of $842,892 and Energy Efficiency program costs of $153,028. Contract services and outsourcing resources accounted for $15 of the $22.6 million while payroll and associated costs accounted for only $5.5 million of the total for that year. Outsourcing resources primarily represent charges from Entergy's outsource Information Technology ("IT") partner, Science Applications International Inc. ("SAIC"). Outside legal and legal related costs made up $5.6 million of the contract services. The majority of the remaining contract work amount was fairly evenly split with continuing work with the UCOS case; business guidance on unbundling operations design and business case analysis; and the initial stages of detailed business process mapping, systems business requirements, and other system support areas.

TTC Costs in 2000 By Major Cost Type (in millions)



Q. DESCRIBE THE REGULATORY ACTIVITIES THAT OCCURRED IN 2000.

A. With respect to proceedings at the Commission, as already noted, EGSI filed its BSP on January 10, 2000 in Docket No. 21957. Consistent with the direction of the Commission at its open meeting on January 13, 2000, matters pertaining to competitive energy services issues were severed from Docket No. 21957 and heard in Docket No. 21984 ("Competitive Energy Services Proceeding"). After a hearing and a revision to the BSP, the Commission issued an interim order approving the BSP on July 25, 2000, and ultimately consolidated the BSP proceeding with EGSI's UCOS proceeding in Docket No. 22356. After a hearing, the Commission issued an order and order on rehearing in EGSI's Competitive Energy Services Proceeding in August and October of 2000, respectively.

In March of 2000, EGSI filed its utility-specific UCOS case in Docket No. 22356. EGSI's UCOS rate filing package consisted of testimony from over 40 witnesses. Contemporaneously, the Commission established Docket No. 22344 to resolve generic issues common to all investor owned utilities' UCOS cases. Activities related to the EGSI-specific and the "generic" UCOS proceedings continued throughout 2000, and the Company continued its involvement in various rulemaking activities. Rulemaking activities included projects that were initiated in 1999 and ongoing during 2000, and many new projects that began during 2000. Again, the various regulatory activities in which EGSI was involved are listed in Exhibit PRM-7. Although Texas was clearly the center of regulatory activities related to ROA, approvals were required in other jurisdictions as well.

Q. PLEASE DESCRIBE EGSI'S ACTIVITIES IN OTHER JURISDICTIONS INITIATED IN THE YEAR 2000 TO SECURE APPROVALS SO EGSI COULD COMPLY WITH SB 7.

A. On June 15, 2000, ESI, on behalf of the Entergy Operating Companies, filed an amendment to the Entergy System Agreement to facilitate the introduction of retail competition in Arkansas and Texas in FERC Docket ER00-2854. The Entergy System Agreement is a FERC-approved rate schedule providing for coordinated operation of the generation and bulk transmission facilities of the Entergy Operating Companies and the allocation of benefits and costs among them. The filing established provisions to release Arkansas and Texas from their obligations under the System Agreement on the effective date of full retail competition to ensure that the System Agreement did not function as an impediment to the implementation of ROA in Arkansas and Texas. The proceeding continued throughout 2000, and the parties settled the ROA-related provisions in May 2001.

In addition, on August 8, 2000, EGSI filed its BSP before the LPSC in LPSC Consolidated Docket Nos. U-21453, U-20925, and U-22092 (Subdocket B) requesting approval to separate EGSI's operations in accordance with SB 7. The filing with the LPSC was necessary because EGSI's retail utility operations are subject to the jurisdiction of both the Commission and the LPSC. The proceedings continued throughout 2000. Those proceedings resulted in settlements and LPSC approval of most but not all issues during 2001. Because the LPSC proceedings were not initiated as part of the SB 7 transition, EGSI has not included the costs associated with the LPSC's review of its BSP in its requested TTC recovery.

Q. PLEASE DESCRIBE EGSI'S IMPLEMENTATION ACTIVITIES DURING 2000.

A. In addition to the regulatory activities described above, considerable implementation planning efforts were also underway during 2000. The impact of impending ROA reached almost every function of every business unit. Each of the business units appointed leads that represented each of their functional areas and worked with the Integration Team. The individual business units were responsible for their own implementation plans and execution; however, these business units and their appointed leads reported on a "dotted line" basis to the Integration Team for the purposes of preparing for ROA.

The Integration Team helped the decision teams and business units analyze the impact that a growing number of rule changes would have on the Company's business processes. Based upon these assessments, the Integration Team worked closely with business units and functional areas across the Company to develop detailed implementation plans and schedules. Accenture was retained to assist in developing and maintaining an integrated implementation plan, and in coordinating the implementation efforts and reporting process.

The development of detailed implementation plans for the business units and functional areas was a very resource-intensive effort. The Commission rulemakings and ERCOT retail market protocols ("ERCOT Protocols") proceedings required EGSI and ESI employee subject-matter experts across a broad spectrum of disciplines to travel to Austin throughout the year to attend almost daily meetings. The Company needed to remain informed about activities and changes in the ERCOT market structure because it was anticipated that ERCOT would ultimately assume some statewide functions (which it did as the Statewide Customer Registration Agent), and that the ERCOT ROA model would have some relevance to how ROA would evolve in ESAT (which it did when it came time to develop the ESAT Protocols).

The Company also retained external subject-matter experts, as necessary, to support the business units' and functional areas' involvement in these meetings. The Company committed considerable resources to these proceedings because a thorough understanding of the language and intent of these rules and a thorough investigation of the impacts such rules would have on the business process were the critical first steps to designing, implementing, and executing the processes necessary to implement ROA. Furthermore, careful attention to detail during the rulemaking processes was crucial because slight differences in the rules could result in large cost increases for implementation and ongoing unbundled operations.

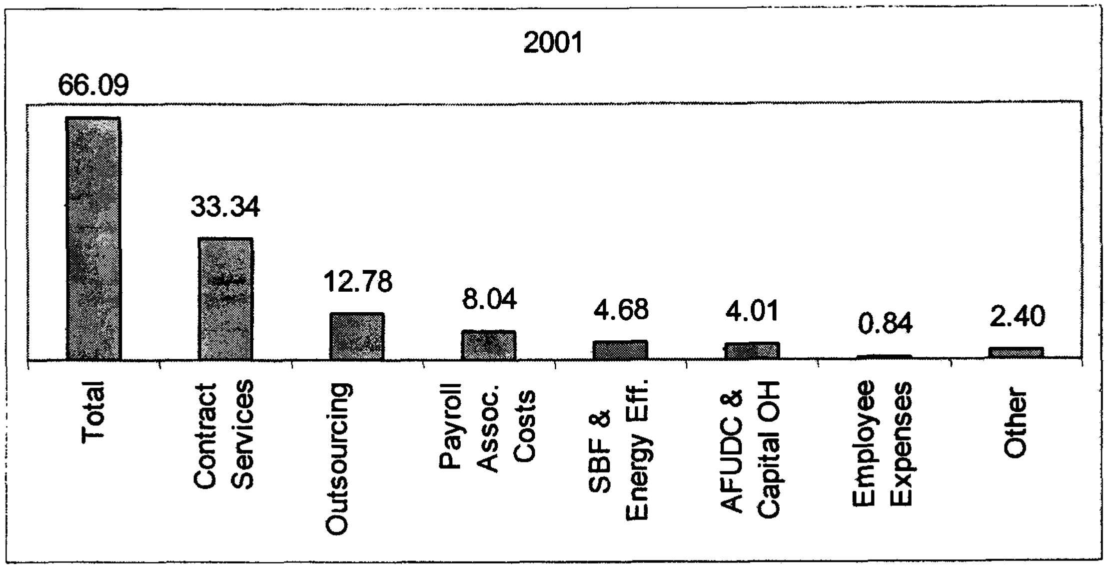
Dedicated teams within each functional area were necessary to investigate the impacts of such rules on business processes. For example, within the distribution function alone, well over 130 business processes were identified, assessed, mapped, and redesigned. These included, but were not limited to, customer switching and registration, market communications/Electronic Data Interchange, billing, market settlement, and financial reporting. As noted, this investigation was a critical first step in implementing ROA.

Q. DESCRIBE THE GENERAL AREAS OF TRANSITION COSTS THAT OCCURRED DURING 2001.

A. The Company incurred $66.1 million in TTC costs in 2001. Transition implementation reached its peak in 2001 as the Company was preparing for the June 1, 2001 start date for the retail pilot and the anticipated January 1, 2002 commencement for ROA. During 2001, a majority of work shifted from regulatory activities (that is, PUCT dockets and projects) to transition implementation where work was done and systems put in place to make the market functional. The major costs were related to process and systems changes required to support the new competitive market. These expenditures include $4.2 million paid to the System Benefit Fund and Energy Efficiency program costs of $483,259. At this point in time, very early in the year, Arkansas had delayed ROA.

In 2001, contract services and outsourcing resources accounted for $33.3 and $12.8 million, respectively, of the $66.1 million, while payroll and associated costs accounted for only $8 million of the total for that year. As described above, the majority of these costs shifted to core business process and systems implementation--over $38 million of the contract work costs were in this area in 2001, primarily Texas SET. Legal remained a critical portion of the effort but significantly less, requiring $5.2 million of contract work that year. Most of that work occurred earlier in the year on the UCOS docket and then later in the year supporting the "Readiness" docket (Docket No. 24469), both of which are addressed in more detail below. By this time AFUDC (Allowance for Funds Used During Construction) and Capital Overhead Clearing charges had begun to accumulate as over $4 million was incurred in 2001.

TTC Costs In 2001 By Major Cost Type (in millions)



Note: Contract Services is shown slightly less than its $33.8 million total because $465,958 of that overall amount is reflected within SBF and Energy Efficiency.

Q. PLEASE DESCRIBE EGSI'S REGULATORY ACTIVITIES DURING 2001.

A. On the regulatory front, most of the rulemakings related to ROA were already complete and only a few were still ongoing into 2001. (*See* Exhibit PRM-7).

The Company's UCOS case progressed at the Commission and culminated with a hearing on a non-unanimous stipulation with a single group of intervenors actively opposing the stipulation and thereby requiring the attendance of many but not all of EGSI's witnesses at the hearing. The Commission approved the non-unanimous stipulation in an interim order issued in May of 2001. Although a final order was never issued in Docket No. 22356 (because EGSI did not move to ROA), the unbundled distribution rates established in that docket were used and available to provide distribution service to customers who would switch to non-affiliated REPs during the ongoing pilot project, which extended from June 2001 through June 2004.

The Company also filed several applications in 2001 in compliance with SB 7 to gain approvals necessary to commence ROA on January 1, 2002. These dockets were:

- Docket No. 24320 – request for approval of the affiliated REP's PTB rates ("PTB Base Rate Proceeding");
- Docket No. 24309 – request for certification of the Southwest Power Pool as a qualified power region ("QPR Proceeding"); and
- Docket No. 24336 – request for approval of the Price to Beat Fuel Factor ("PTB Fuel Factor Proceeding").

The PTB-related proceedings progressed during 2001. The Commission issued final orders in March of 2002 and September of 2003 in Docket No. 24230 and Docket No. 24336, respectively. However, issues at the federal level stalled the QPR Proceeding. On July 12, 2001, the FERC issued an order that rejected the application of the Southwest Power Pool and the Entergy Operating Companies for approval of an RTO, and instead directed the Entergy Operating Companies to participate in mediation for the purpose of facilitating the formation of a single RTO for the southeastern region of the United States. As a result of these developments, EGSI moved to abate the procedural schedule in

Docket No. 24309 and, in July 2001, the Commission approved the motion. Shortly thereafter, a Commission proceeding aimed at delaying the commencement of ROA in EGSI's Texas service territory began in Docket No. 24469.

Q. PLEASE DESCRIBE THE COMMISSION PROCEEDING THAT DELAYED THE COMMENCEMENT OF ROA IN EGSI'S TEXAS SERVICE AREA BEYOND JANUARY 1, 2002.

A. On August 3, 2001, the Commission Staff filed a petition in Docket No. 24469 (the "Readiness Docket") to determine readiness for retail competition for portions of Texas within the Southeastern Electric Reliability Council ("SERC"), that is, in the Company's Texas service territory, or ESAT. In December 2001, the Commission approved a non-unanimous agreement in the Readiness Docket that delayed ROA and established a new target date of not prior to September 15, 2002 for the commencement of ROA in ESAT.

The Commission's order in the Readiness Docket also set forth a number of milestones that were to be accomplished before the implementation of ROA. These milestones included the development of market protocols, a proceeding to determine the independence of the entity operating and administering access to the transmission system in ESAT, and another "readiness" proceeding, in which the Commission would make the final determination of whether ROA would be implemented in ESAT.

Q. DESCRIBE THE IMPLEMENTATION ACTIVITIES THAT OCCURRED IN 2001.

A. Although the Commission delayed ROA for ESAT from the original commencement date of January 1, 2002, the Commission's order in the Readiness Docket was not issued until December 20, 2001. Consequently, the Company was compelled to continue a full-scale ROA implementation effort until the end of 2001, assuming until then that ROA would commence on January 1, 2002.

Through 2001, the Company continued to actively participate in the ERCOT Protocols change process, monitored and implemented new market requirements and flight testing, and continued developing and testing all of its new systems and modifications to its legacy systems.

Also, the ongoing ERCOT collaborative proceedings produced significant changes to the initial implementation plans for the standardized systems to be used by all market participants for retail customer enrollment and switching. As a result, costs for the base level of systems needed to support ROA throughout Texas grew substantially for ERCOT and all market participants in 2001, including EGSI. The growing number of rule changes required that ERCOT implement new or revised SET (again, "Standard Electronic Transaction") releases to manage the changes. Each SET release required new rounds of system work and testing. To be clear, these SET releases applied to all Texas utilities that were moving to ROA, regardless of whether they were inside or outside of ERCOT. Changes were made to the existing ERCOT market software before moving onto the next full SET version. In order to maintain stability, ERCOT installed these changes in batches and market participants were required to fully test each batch of changes in what was referred to as "flight tests." In addition to the flight tests associated with version upgrades, ERCOT also ran several flight tests each year for new market entrants.

ERCOT's initial SET release was rolled out in June 2000. From 2000 to 2001, there were over 130 changes made to the various SET versions. While the more than 130 actual changes are in and of themselves significant, more than another 230 changes were submitted for evaluation. As I stated previously, even proposed changes required significant cost and effort as teams labored to understand the intent of the proposed changes and assess the potential impacts on business processes. The constant evaluation and/or implementation and testing of changes in market mechanics systems caused the Company to incur substantial costs.

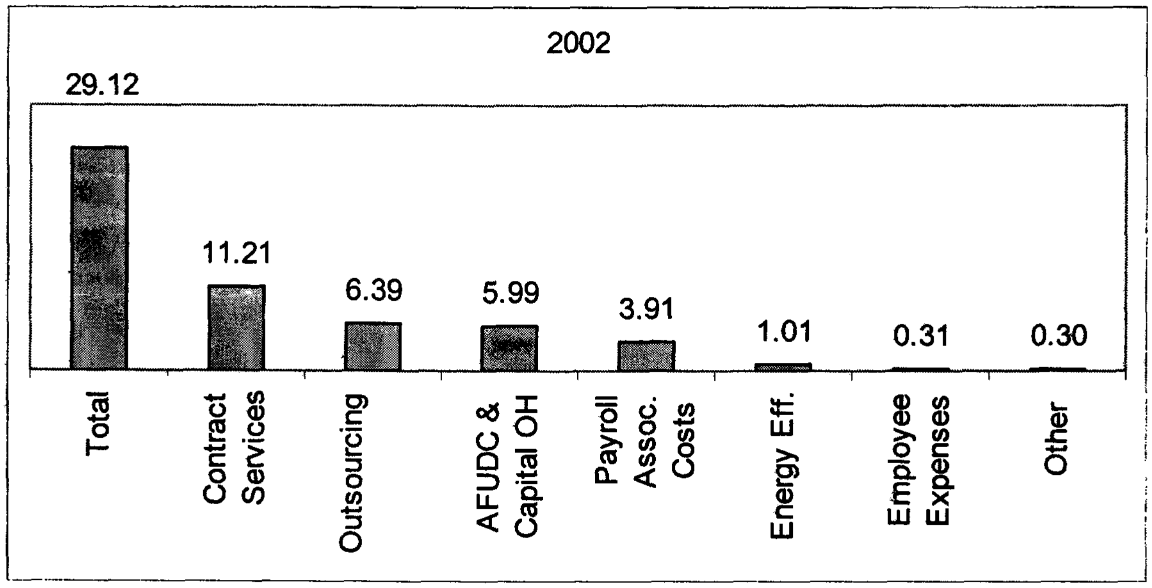
The new market requirements had a significant impact on the Company's legacy systems and processes. Legacy systems are those existing systems that are already providing needed functionality to EGSI and the other Entergy Operating Companies. EGSI is a multi-jurisdictional entity and part of a larger multi-jurisdictional system. The separation and unbundling of the systems relating to EGSI was challenging because it was critical that the changes required by SB 7 not unduly impact the other Operating Company jurisdictions that would remain regulated. Therefore, teams were established to focus on all of the corporate systems and functional areas. These teams carefully developed plans to implement these new market requirements with minimal impacts on EGSI's Louisiana operations and the operations of its other affiliates.

Q. DESCRIBE THE GENERAL AREAS OF TRANSITION COSTS THAT OCCURRED DURING 2002.

A. The Company incurred approximately $29.1 million in TTC costs in 2002. These costs were incurred primarily to maintain ROA and pilot readiness and include $1,012,535 in Energy Efficiency program costs. Systems had to be maintained and kept up to date with ERCOT standards and testing procedures. EGS was required to stand ready to serve any retailer that wished to participate in our service territory as soon as it notified the Company.

In 2002, contract services accounted for $11.21 of the $29.1 million while outsourcing resources was $6.4 million. Payroll and associated costs accounted for only $3.9 million of the total for that year, less than half from the previous year. AFUDC and Capital Overhead Clearing continued to accumulate charges accounting for $6 million. A portion of the Company's contract services expenditures was for required legal support in several key dockets, but the majority of the contract services expenditures focused on supporting the open pilot and maintaining readiness for systems necessary to support a full market opening.

TTC Costs in 2002 By Major Cost Type (in millions)



Q. DESCRIBE THE REGULATORY ACTIVITIES THAT OCCURRED IN 2002.

A. As noted previously, the Commission's order in Docket 24469 set forth milestones that were to be accomplished for the implementation of ROA. This resulted in a number of proceedings, which ran continually, and sometimes in parallel, from December of 2001 until the Commission's July

12, 2004 order in Docket No. 28818 to delay ROA indefinitely until an appropriate independent organization is in place.

Project No. 25089 to develop the ESAT market protocols (the "ESAT Protocols Project") began with a kick-off meeting on December 17, 2001 and continued through the end of 2003 with an intense effort to determine the rights and obligations of the various market participants in the ESAT market upon the implementation of ROA. The ESAT Protocols Project included an extended period of collaborative and settlement meetings among the interested participants, as well as three hearings on the merits to address issues that could not be resolved through negotiations among the stakeholders (May 1, 2003, June 17, 2003, and August 20, 2003). The Commission ultimately adopted a non-unanimous settlement setting forth a resolution of the remaining contested issues in the ESAT Protocols Project (which had been converted to a contested case docket—Docket No. 25089—in early 2003).

While progress was being made in the ESAT Protocols Project, it became apparent to various parties to the Readiness Docket that the target dates set in Docket No. 24469 would not be met. Therefore, several signatories to the non-unanimous agreement in Docket No. 24469 filed a petition on June 25, 2002 in Docket No. 26168 requesting that certain deadlines be extended. Among other deadlines, the parties requested that the June 15, 2002 date for deciding whether to pursue an interim solution due to the lack of a fully functional FERC-approved RTO in ESAT be extended to January 15, 2003, and the date for advising the Commission of the RTO status scheduled for June 25, 2002 be extended until January 24, 2003. Also, the participants requested that the date for filing the ESAT market protocols with the Commission be extended from July 1, 2002 to January 31, 2003.

The Commission considered these requests at its July 11, July 25, and August 23, 2002 open meetings. Pursuant to the Commission's request, on July 23, 2002, EGSI filed a proposed timeline outlining the transition to competition in its Texas service area, and filed a modified proposed timeline on August 16, 2002 reflecting a two-month delay in activities leading to ROA that moved the ROA commencement target date from January 2004 to March 2004. In its order, the Commission reiterated its commitment to customer choice in ESAT but recognized that achieving milestones necessary to introduce ROA involved activities in other jurisdictions. Specifically, the Commission ordered that EGSI file on January 24, 2003 a proposal for pursuing an interim solution if a FERC-approved RTO was not expected to be fully functional by January 1, 2004. In addition, the Commission granted the other extensions requested in the petition. Accordingly, starting toward the end of 2002, the Company began to turn its attention to development of an "interim solution," that is, a path to ROA that was not dependent on the establishment of a FERC-approved RTO.

Q. AFTER THE COMMISSION'S DECISION TO PURSUE AN INTERIM SOLUTION, WHAT EFFORTS TOOK PLACE TO ACHIEVE THE MILESTONES NECESSARY TO COMMENCE ROA IN ESAT?

A. An intensive effort was undertaken in the ESAT Protocols Project to convene a series of collaborative sessions with market participants to develop the retail and wholesale protocols. The participants continued their work on the market protocols throughout 2002, and, on January 31, 2003, filed with the Commission the market protocols developed in the project. The participants were able to resolve all but eleven important issues related to the protocols.

In that filing, the participants referred to the protocols as the "Protocols for Customer Choice in the Entergy Settlement Area of Texas," the Entergy Settlement Area of Texas meaning that portion of the Entergy Control Area within Texas, excluding municipally-owned utilities and electric cooperatives that do not offer customer choice. Thus, the protocols became known as the ESAT Protocols.

Q. DESCRIBE THE IMPLEMENTATION ACTIVITIES THAT OCCURRED IN 2002.

A. The Company maintained its fully staffed approach to implementation through the early second quarter of 2002. Teams of employees and contractors continued to track and adjust systems for ERCOT changes and re-adjust cutover plans. But, without a clear date for the commencement of ROA, maintaining this level of resources and readiness became costly and unworkable. At that point, the Company "ramped down" its implementation activities to a more cost effective and practical maintenance and monitoring level of resources.

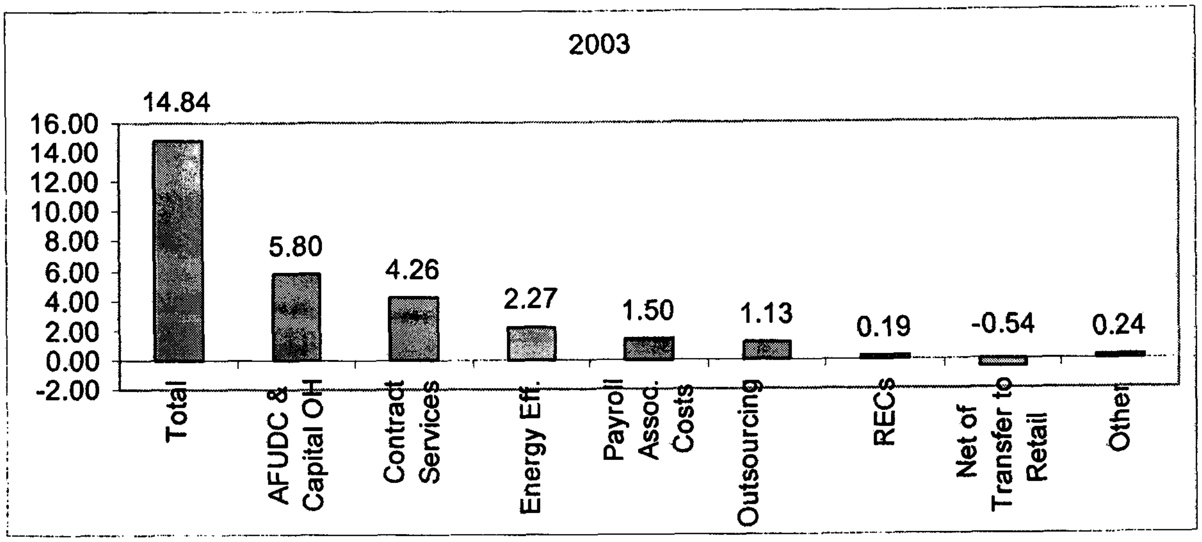
The Company stayed engaged at ERCOT with fewer resources, tracked the changes, continued to work with ERCOT, and continued flight testing to maintain market certification as SET versions changed. The results of the Company's effort to ramp down were readily evident as the monthly costs dropped substantially. The Integration Team was reduced, and services procured from Accenture were scaled down to a minimal role while the Company continued to monitor implementation readiness.

Despite this ramp down, the Commission required that the Company maintain pilot readiness so that REPs could participate in the pilot at any time. Maintaining this readiness required EGSI to continue to pay ERCOT fees, retain a minimum level of service from VeriTran (EGSI's market interface vendor), and maintain a minimum level of finance and IT support. These steps enabled the Company to perform market communications, keep up with SET version changes, including flight testing, and operate the pilot.

Q. DESCRIBE THE GENERAL AREAS OF TRANSITION COSTS THAT OCCURRED DURING CALENDAR YEAR 2003.

A. The Company continued its ramp down mode while maintaining the readiness required. Costs were reduced by almost half from the previous year as the Company incurred $14.8 million in TTC costs in 2003. This includes $2,267,415 in Energy Efficiency and $192,635 in Renewable Energy Credit ("RECs") program costs. Well over a third of that total cost was the continuing accumulation of AFUDC and Capital Overhead Clearing charges - $5.8 million. Contract work and outsourcing makes up most of the rest of the amount - $4.3 and $1.1 million respectively. The majority of the contract costs was for ongoing support of the pilot and systems readiness. A net credit of $542,888 to the overall TTC request occurred as a result of moving charges off of the Company's books and onto the Retail affiliate's books. I will discuss this net credit later in the Default Service Provider Class position of my testimony. Internal cost reductions mirrored the overall reductions as internal costs dropped by more than half from the previous year - $1.5 million in 2003.

TTC Costs in 2003 By Major Cost Type (in millions)



Q. DESCRIBE THE REGULATORY ACTIVITIES THAT OCCURRED DURING 2003.

A. The Company's ROA-related activities for 2003 were highly dependent upon whether or not a FERC-approved RTO would be fully functioning by January 1, 2004. The remaining active signatories to the non-unanimous agreement in the Readiness Docket determined that it was unlikely that a FERC-approved RTO would be fully functioning by January 1, 2004. Accordingly, EGSI filed a proposal for an interim solution on January 24, 2003 in Docket No. 27273 (the "Interim Solution Docket").

In the Interim Solution Docket, EGSI proposed that the Entergy Operating Companies' existing transmission organization would serve as the ESAT "Transmission Authority" under the supervision of an independent third-party overseer, if such oversight were deemed necessary. EGSI further proposed that the Commission establish January 1, 2004 as the date-certain for commencement of ROA in ESAT and, alternatively, if that date was not or could not be met, the Commission allow EGSI to cease all activities associated with the transition to ROA, except jurisdictional separation, until January 1, 2007.

The Company made this alternative recommendation, in January 2003, because of the significant costs incurred by EGSI and others to proceed with ROA, and the difficulty of undertaking future business and resource planning without a date certain for the commencement of ROA in ESAT. In an order dated July 25, 2003, the Commission endorsed the concept of an interim solution (later abandoned in Docket No. 28818) as proposed by EGSI, *but* rejected the Company's recommended deadline of January 1, 2004 for implementing ROA:

> The Commission finds that an interim solution may be appropriate, but disagrees with the approach set forth in Entergy's petition, particularly with regard to the "drop dead" date of January 1, 2004. It is neither reasonable nor efficient to cease all competitive-transition activities and expenses if retail competition cannot begin on that specific date. Entergy's proposal does not provide adequate time to achieve the necessary milestones and to make informed decisions regarding the market protocols, certification of an independent organization, and market readiness. Perhaps more importantly, Entergy's proposal would not allow continued progress to be made if the competitive market was not ready—for any reason—on January 1, 2004. The Commission seeks to introduce competition as quickly as possible, but it is essential to complete the necessary groundwork in a way that will lead to a successful and fully functional market—even under an interim solution. While January 1, 2004 may not be feasible, it appears reasonable at this point to start competition under an interim solution.

The Commission's order expressly anticipated that "an interim solution may begin by December 2004." At that time, the Commission continued to establish a near-term implementation target date, and also issued a timeline for the commencement of ROA in ESAT having various milestones as shown on the attachment to the Commission's Order on Rehearing in the Interim Solution Docket. A copy of that order (with the Commission's timeline attachment) is included as my Exhibit PRM-8. For example, by September 2003, the Commission expected to issue a decision on the ESAT Protocols. The Commission and the participants met that Protocols deadline.

Further, following the Commission's order that approved the ESAT Protocols, ESI on behalf of the Entergy Operating Companies filed an application on October 9, 2003 pursuant to Section 205 of the Federal Power Act requesting FERC approval of the FERC-jurisdictional provisions in the ESAT Protocols. The FERC docketed ESI's application in FERC Docket No. ER04-35-000. In an order issued December 22, 2003, the FERC found that: the ESAT Protocols were consistent with or superior to ESI's pro forma open access transmission tariff; accepted the ESAT Protocols with minor modifications to become effective on the commencement of ROA in ESAT; and directed ESI to make a compliance filing incorporating the minor modifications made by the FERC.

Also, on November 26, 2003, EGSI filed its application for certification of an Independent Organization for ESAT. EGSI filed this application in Docket No. 28818 (the "Independent Organization Docket"). It was filed in accordance with the Commission's decision to proceed with an interim solution, and tracked the structural proposal submitted by EGSI in the Interim Solution Docket; that is: the ESAT Independent Organization, under an interim solution, would be the Entergy Operating Companies' existing transmission organization, under the supervision of an independent third-party overseer entity (if such was necessary).

At this time, Entergy (including EGSI) was continuing to pursue implementation of a FERC-jurisdictional RTO that, once implemented, would supersede the interim solution and the Entergy transmission-based ESAT Independent Organization. The RTO that Entergy was pursuing was known as SeTrans, which was an RTO that would cover many states and utilities in the southeastern United States. Recall that the FERC, in the summer of 2001, had directed Entergy to pursue a southeastern-based RTO. However, in early December 2003, efforts to implement SeTrans were suspended. The demise of the SeTrans RTO proposal prompted the Commission to request briefing on whether the Commission should delay further efforts to establish ROA in ESAT until after a FERC-approved RTO is in place. These issues would be addressed in 2004.

Q. DESCRIBE EGSI'S IMPLEMENTATION ACTIVITIES DURING 2003.

A. The Company continued its efforts to minimize implementation costs and closely monitored all other transition-related costs. As required, EGSI maintained immediate readiness for its pilot project, maintained the various systems supporting the pilot and retail access and updated systems, as required, to stay current with the technical ERCOT flight tests.

In the fall of 2003, one REP entered the pilot to serve commercial customers; fewer than 20 non-IDR meters were involved. Implementation support was also involved in ongoing efforts to develop the interim solution and the ESAT Protocols. These efforts required operational studies and cost analysis of various alternative solutions and specific protocols.

The Integration Team continued to operate at reduced capacity but, with assistance from Accenture, made periodic assessments of the Company's readiness. The team also directed the business units and functional areas to reassess their budgets and implementation plans and revise the budgets and plans based upon a target date for commencing ROA by late third quarter to early fourth quarter of 2004. Ultimately, implementation activities remained ramped down until these revised budgets and plans were used in January of 2004 to once again "ramp up" preparation for ROA based on the Interim Solution Docket target date of December 2004 and the approval of the ESAT Protocols.

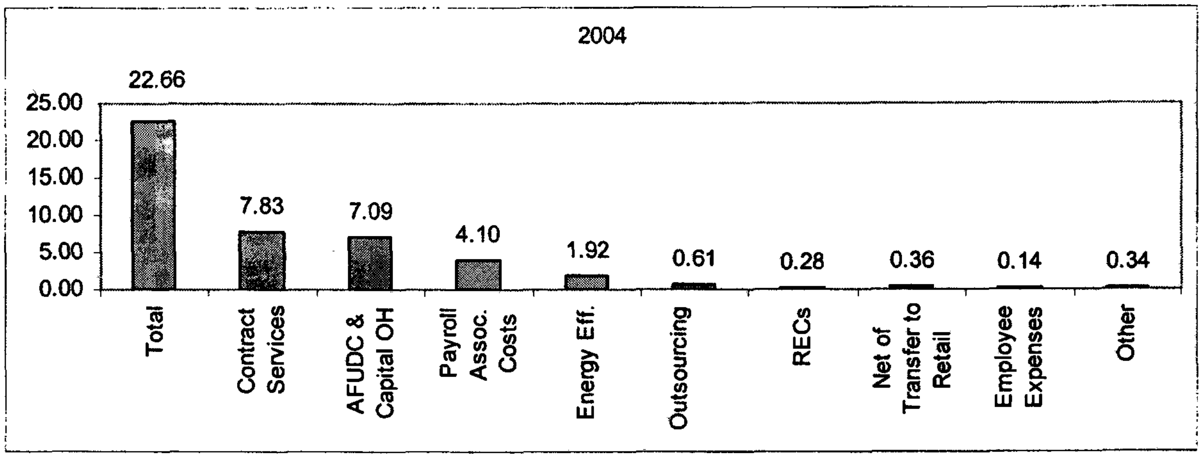
Q. DESCRIBE THE GENERAL TRANSITION COSTS THAT OCCURRED DURING 2004.

A. The Company incurred $22.7 million in TTC costs in 2004. These costs include $7.1 million in AFUDC and capital overhead; $1.9 million in Energy

Efficiency; $277,034 in RECs; and $6 million in rate/rider case development costs that included recovery of transition to competition and capacity costs.

Based on the Commission and FERC approval of the ESAT protocols, starting in late 2003 and early in 2004, the Company began another ramp up in order to implement ROA on or by January 1, 2005. Given the scope of work that still remained (including remaining compliant with the state-wide SET requirements), the Company could not wait for a final decision in the Independence and anticipated Market Readiness dockets to begin final preparations for full implementation. The Company also maintained a number of systems as it had since the delay order. These preparation and maintenance costs, along with the regulatory efforts, made up the remaining approximately $7.4 million. Due to the continuation of this level of costs it became increasingly important that the Company achieve certainty with respect to the fundamental question of whether it would unbundle and implement ROA in the near-term, or remain a bundled regulated utility.

TTC Costs In 2004 By Major Cost Type (in millions)



Q. DESCRIBE THE REGULATORY ACTIVITIES THAT OCCURRED IN 2004.

A. The primary regulatory transition activity involved EGSI's Independent Organization proposal, and whether to continue to pursue ROA under an interim solution in light of the suspension of efforts to pursue the SeTrans RTO. In response to the Commission's request for briefing on the SeTrans question, EGSI, in its January 15, 2004 brief, argued that the suspension of efforts to develop the SeTrans RTO should not delay further efforts to establish ROA in ESAT because the interim solution, which the Commission had directed that the parties pursue, was, by its nature, not dependent on a FERC-approved RTO being in place—it was an "interim" solution. EGSI, however, also re-iterated its request for certainty regarding achievement of ROA in the near-term:

> If, however, the Commission concludes that ROA in ESAT cannot commence unless there is at least some expectation that an RTO will be implemented in the foreseeable future, then EGSI requests that the Commission order, at the January 29, 2004 open meeting, that all efforts to achieve ROA in ESAT shall cease. Above all, EGSI requests certainty—certainty that either: (1) ROA will be achieved in the near-term; or (2) if ROA is not a near-term option, then cease efforts to achieve ROA in the ESAT region, and devote attention and resources to other matters. (Jan. 15, 2004 brief at 1-2.)

On March 15, 2004, the Commission issued its preliminary order finding that it was *not* necessary to delay further efforts to establish competition until after a FERC-approved RTO was in place. In that preliminary order, the Commission also eliminated the December 2004 target date for ROA established previously in Docket No. 27273, and instead concluded that "[b]ased on its experience over the past several years, the Commission finds that it is not feasible, or even useful, to set another target date at least until the market-readiness proceeding is underway."

Ultimately, and finally, at its June 9, 2004 open meeting, the Commission voted to grant the Company's request for certainty by deciding (1) to reject the Company's Independent Organization proposal, and (2) that efforts to implement ROA prior to an implementation of a FERC-approved RTO for ESAT (or other Commission-approved independent entity) should cease. As a result of the Commission's decision to not implement ROA under an interim solution (and the lack of an RTO in the 2002 time frame), the Company prepared and filed a base rate case in Docket No. 30123 on August 25, 2004, which I discuss in more detail later in my testimony.

Q. WHAT IMPLEMENTATION ACTIVITIES OCCURRED DURING 2004?

A. Although the July 12, 2004 order in Docket No. 28818 provided the near-term certainty that EGSI sought, the Company's implementation efforts had already ramped up in the first quarter of 2004 based upon the belief that the Commission and FERC approvals of the ESAT Protocols bode well for initiation of ROA in the near term. Initial tasks involved assessing and revising the Company's implementation plans to achieve ROA in the near term. Following that, efforts focused on re-acquiring outside resources and re-engaging internal personnel to quickly ramp up to the appropriate level of resources consistent with the revised plan. EGSI ramped these efforts back down to the previous lower level in April after the Commission eliminated the December 2004 target date for ROA through its preliminary order in Docket No. 28818.

In June 2004, the Commission, after convening its hearing to address EGSI's Independent Organization filing, orally ruled that it would cease further efforts to implement an interim solution and also terminated the pilot project. The Commission followed this June oral ruling with a written order in July 2004.

Q. WHAT REGULATORY ACTIVITIES CONTINUED AFTER THE COMMISSION TERMINATED THE INTERIM SOLUTION EFFORTS AND PILOT PROJECT IN THE SUMMER OF 2004?

A. A few activities did continue. First, the Commission's Staff, the Alliance for Retail Markets ("ARM"), and the Texas Industrial Energy Consumers ("TIEC") filed motions for rehearing of the Commission's July 2004 written order in Docket No. 28818 that terminated the pilot project. EGSI opposed those motions, and the Commission declined to reconsider its decision terminating the pilot project. Subsequently, ARM and TIEC both filed appeals of the Commission's Docket No. 28818 order in Travis County District Court. EGSI intervened in that appeal and continued to support the Commission's decision to terminate the SB 7 customer choice pilot project.

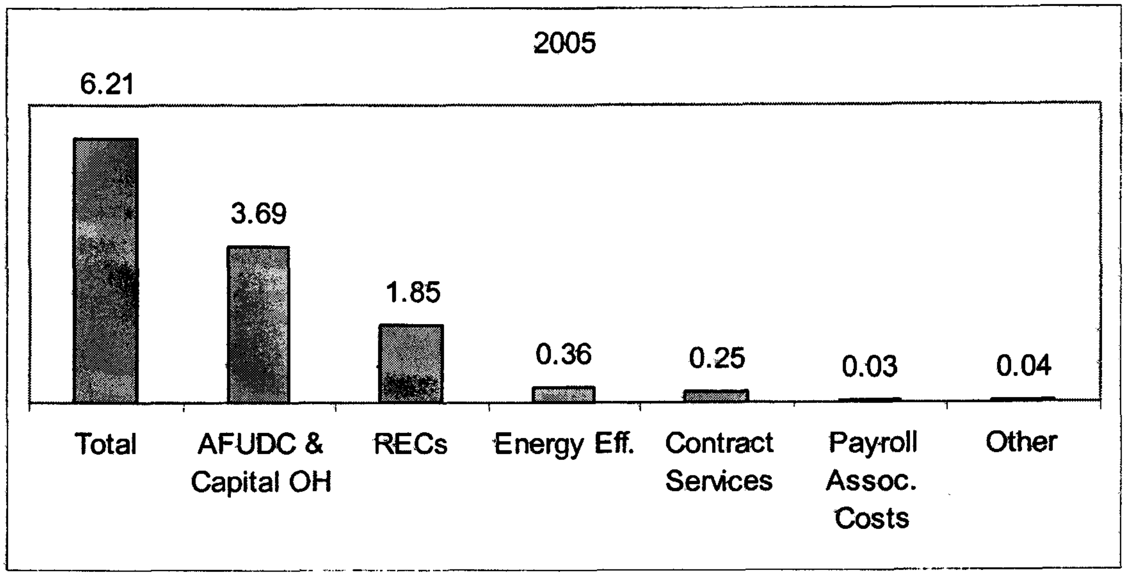
Also, when it appeared in the spring of 2004 that the PUCT might indefinitely delay ROA in ESAT, EGSI began preliminary work on a base rate case/TTC Rider filing. This project kicked into high gear in June 2004 when the Commission terminated the Interim Solution path for ESAT ROA, and rejected the Company's interim Independent Organization proposal. The Commission did not, however, terminate the ROA requirement for ESAT, or set a time-certain delay. EGSI, therefore, prepared and filed a request for a base rate increase, which included a TTC rider request and incremental capacity rider request. The Company believed this filing to be consistent with SB 7, and in particular with PURA

§ 39.103, which authorizes the Commission to establish new rates upon ordering a delay in the implementation of ROA. The Company also believed the filing to be consistent with the terms of the delay in implementing ROA that were established in Docket No. 24469. This filing was also necessitated by the now-lengthy period during which EGSI's rates were insufficient to recover its ongoing operating and TTC costs, let alone to provide a fair return. This application, which involved a great deal of effort and resources on the Company's part, was filed on August 25, 2004 in PUCT Docket No. 30123. The Commission, however, rejected that filing in October 2004 on the basis that the filing was precluded by the terms of the non-unanimous settlement adopted by the Commission in the Readiness Docket as the basis for delaying ROA in ESAT. EGSI filed for rehearing of that order, which the Commission denied. The Company then filed an appeal of that order in the Travis County District Courts.

Q. DESCRIBE THE GENERAL TRANSITION COSTS THAT OCCURRED DURING 2005.

A. The Company incurred $6.2 million in TTC costs in 2005 through June 17 when House Bill 1567 was signed into law by Governor Perry. Over half of these costs were due to continuing AFUDC—$3.7 million. Another $1.8 million was for the SB 7 mandated purchase of RECs; Energy Efficiency programs accounted for $358,869.

TTC Costs In 2005 By Major Cost Type (in millions)



Q. PLEASE SUMMARIZE YOUR FOREGOING DISCUSSION REGARDING EGSI'S TRANSITION ACTIVITIES AND THE COSTS ASSOCIATED WITH THESE ACTIVITIES.

A. The foregoing discussion provides support for the necessity and reasonableness of the overall level of EGSI's TTC costs. (Additional support for the necessity and reasonableness of each of the specific TTC classes is discussed below by me and in the testimony of other Company witnesses.) As discussed above, the regulatory proceedings before the Commission, which SB 7 set into motion with diverse parties having different interests, did not always lend themselves to producing answers at low cost. On numerous occasions, EGSI had to litigate contested issues and incur additional costs, including its support for the non-unanimous settlements in the Readiness Docket and the ESAT Protocols docket. In addition, to comply with SB 7, EGSI had to seek approvals from its other regulators. Also, as discussed above, the iterative process that emerged for establishing market mechanics systems (the evolving SET versions in particular) did not lend itself to implementation at low cost. Finally, as discussed above, the requirement for EGSI to participate in pre-ROA activities, or continue operating pre-ROA projects such as the pilot project, contributed to the level of the TTC costs over an extended period of time. In light of these facts discussed in detail above, EGSI's request to recover $164.2 million in costs incurred over a six-year period is reasonable.

Further, when one compares EGSI's TTC costs incurred by year to the timeline of events discussed above, that comparison provides assurance that EGSI's TTC costs are reasonable because the increases and decreases in the level of TTC costs over the period 1999 through 2005 mirror requirements, filings, proceedings, and events with which the Commission is familiar. Company witness Cuddy also explains why the overall levels of costs incurred by or on behalf of EGSI in its transition efforts were reasonable when compared to an independent estimate of what such efforts would cost, and to similar or analogous efforts by other entities.

B. Derivation of the EGSI-Texas TTC Costs

Q. HOW, SPECIFICALLY, WERE TTC COSTS FOR EGSI ASSIGNED TO EGSI-TEXAS?

A. As explained previously, TTC costs were compiled for this filing based on project codes that represented major components or costs associated with ROA. These project codes include costs directly incurred by EGSI (non-affiliate costs) and costs billed to EGSI by affiliates (affiliate costs) for services in support of ROA. In order to appropriately assign TTC costs to EGSI-Texas, the Company first identified project codes that were only associated with ROA activities in Texas. Non-affiliate costs in these project codes were assigned 100% to EGSI-Texas. Affiliate costs were assigned similarly.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW AFFILIATE TTC COSTS WERE ASSIGNED TO TEXAS.

A. Billing Methods "EGSI" and "TTC" are the predominate billing methods that are applied to the projects that encompass TTC costs and distribute charges to EGSI. For example, ESI services provided under a TTC project code with Billing Method EGSI were billed 100% to EGSI. Because TTC costs captured under these direct billed projects were associated with the transition effort for EGSI-Texas only, these TTC costs were billed in their entirety to EGSI-Texas and not EGSI-Louisiana. Similarly, costs charged to an ROA-related project with Billing method

"TTC" would bill charges to EGSI that would be assigned in their entirety to EGSI-Texas because there are no TTC-related activities for EGSI-Louisiana. Thus, if charges are billed to a Texas ROA-specific project (such as a TTC implementation project), the "EGSI" or the "TTC" billing method applied to that project would assign all of those charges to EGSI-Texas.

Q. ARE THERE ANY OTHER METHODS THAT THE COMPANY EMPLOYED TO ASSIGN TTC AFFILIATE COSTS TO TEXAS?

A. Yes. In the early stages of the transition to competition, the Company captured certain ESI TTC affiliate charges and billed these costs to affiliates based on ESI allocation methods that distributed charges to all of Entergy's regulated utilities. At that early phase of the transition effort, all of Entergy's regulated utilities were considered candidates for ROA, thus all companies were driving the need for the incurred costs. Costs captured under these project codes that were billed to EGSI were assigned to both EGSI-Texas and EGSI-Louisiana. For example, Transition Management Implementation costs were captured under project code TRALIM and distributed to Entergy's regulated utilities based on Billing Method "35." Charges billed to EGSI in this instance were assigned to both EGSI-Texas and EGSI-Louisiana because, at that time, both jurisdictions drove the needs for the services provided under this project, because both were ROA candidates.

Company witness Barrilleaux discusses the billing method process in more detail in his testimony.

Q. ARE DIFFERENCES IN THE SIZE OF A UTILITY'S CUSTOMER BASE A SIGNIFICANT FACTOR IN THE LEVEL OF TTC COSTS?

A. No. For a transition-type effort, the number of customers served by a utility is neither the principal nor the sole driver of the amount of transition costs incurred by a utility. These costs fall into two broad categories: (1) regulatory-related costs and (2) utility business processes and systems changes. As I discussed at length in the TTC Cost Trend section of my testimony above, the regulatory process in Texas was enormous, complex, and lengthy. These TTC costs were incurred over a six-year period, rather than a shorter two and one-half-year period, as was originally anticipated through SB 7. Further, this effort required significant support by outside counsel, with regard to both time and expense, for the over 50 dockets and rulemakings in which the Company was involved. A significant portion of the expenses included in EGSI's TTC costs is associated with these regulatory proceedings. In that regard, SB 7 placed a similar regulatory burden on the Texas portion of EGSI as it did for TXU and Reliant despite the significantly greater size of the latter two companies. The level of costs to implement ROA, therefore, is driven by the amount of work required to establish the market and participate in the required and necessary Commission dockets, regardless of the number of customers that the utility might have.

A second driver of costs is the changes needed in the utility business processes and systems. The Texas market structure and ERCOT Protocols are complex and created the need for systems to support large volumes of many different types of transactions. The Company estimated that the retail ERCOT Protocols (required by all Texas distribution companies, not just ERCOT) would generate over one million market transactions a month. The volume of transactions and the complexity of rules demanded robust systems and controls to appropriately support the level of service envisioned by the Commission. The base level of functionality required for this volume within a large, integrated entity is not tremendously different from one that must support several times this volume of transactions. EGSI incurred the cost to design, build, and maintain this base level of functionality within its support systems.

Q. WHAT ARE THE DETERMINING FACTORS BEHIND THE BASE LEVEL OF FUNCTIONALITY THAT EGSI WAS REQUIRED TO BUILD?

A. The requirements for a particular solution are driven by a number of factors. These factors include complexity of the market protocols, types of different transactions, expected volume of transactions, number of legacy systems that are impacted, complexity of those legacy systems which need to interface with the new systems, and the levels of system controls and monitoring reporting capabilities needed. Specifically the level of effort for even this core solution is dependent upon:

1) Robustness - systems would be designed and built to be suitably robust to support the functionality as required by market protocols and the anticipated volume of transactions (estimated to be more than one million transaction per month) to interact with the market;
2) Controls – given the large volume of transactions, adequate controls were required to provide timely processing while identifying and addressing exceptions in the market mandated timeframe;
3) Automation – systems would be sufficiently automated to manage the large volume of transactions and avoid large increases in staffing;
4) Limited impact to other jurisdictions – Entergy's existing legacy systems provide essential functionality for a large, multi-jurisdictional utility: the design of systems required significant efforts to assess the legacy systems and develop appropriate interfaces to extract essential information (for instance, the need to develop consolidated financial statements with the other Entergy Operating Companies); and
5) Retention of functions – since Entergy's existing legacy systems already provided distribution customers with comprehensive and robust service, the goal of the core market solution would be to at

least maintain that level of service for the remaining Distribution functions.

Given the comprehensive requirements of the Texas market rules and ERCOT Protocols, the volume of transactions and customers as well as the points discussed above, the creation of this comprehensive market solution, while less than if the effort were for the entire Entergy service area, still was a very significant effort.

C. Allocation of TTC Costs to Customer Classes

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE THE TTC COSTS TO EGSI-TEXAS'S CUSTOMER CLASSES?

A. The Company proposes to allocate the TTC costs assigned to EGSI-Texas on a 50/50 weighting between Demand (Average and Excess / Four Coincident Peaks) and Energy (kilowatt-hours).

Q. IN THE COMPANY'S 2004 TEXAS RATE CASE FILING, THE COMPANY PROPOSED TO ALLOCATE TTC COSTS TO CUSTOMER CLASSES BASED ONLY ON ENERGY (KWH). WHY IS THE COMPANY NOW PROPOSING TO ALLOCATE THE TTC COSTS TO CUSTOMER CLASSES ON A 50/50 WEIGHTING BETWEEN DEMAND AND ENERGY?

A. In the Company's 2004 rate case filing (which included a request to recover a portion of EGSI's TTC costs), I proposed that those TTC costs would be allocated to customer classes by energy on a kWh basis. While there may be merit to the energy-only based allocation, it is also true that the primary intended benefit of ROA was to make the generation or production function competitive. Costs within the production function could be characterized and segregated as fixed costs and variable costs. It would be difficult to ascertain with any certainty, however, what competitive benefits could be ascribed to savings in fixed costs versus savings ascribed to variable costs. As a result, the allocation of TTC costs is a regulatory policy issue.

As a policy issue, the Company takes note of two policy decisions that support an allocation of TTC costs on a 50/50 weighting between demand and energy. First, I note that in PURA § 39.253, the Texas Legislature required that stranded costs in the form of capital costs incurred to improve air quality would be allocated on a 50/50 basis: with 50 percent on the basis of the underlying asset (demand in the case of EGS) and 50 percent energy. I understand that all other stranded costs were allocated based on methods used to allocate the underlying assets. My point here is that the only allocation that was specifically (or "generically") prescribed was done so on a 50/50—energy/demand—basis.

I also understand that the Commission approved a 50/50—energy/demand—allocation for Southwestern Public Service Company's (SPS's) recovery of its transition costs in Docket No. 25088. (This is shown in the Supplemental Direct Testimony of SPS witness James M. Elliot, at Exhibit JME-S1, filed on March 22, 2002 in Docket No. 25088.) The Commission approved this 50/50 allocation as part of a unanimous settlement in that docket.

Based on the stranded cost and SPS approaches, the Company supports the allocation of TTC costs on the basis of 50 percent Demand (Average and Excess / Four Coincident Peaks) and 50 percent Energy (kilowatt-hours).

Company witness Myra Talkington uses this 50/50 allocation method to design the TTC rate and supports the TTC Rider tariff.

III. SPECIFIC TTC COST CLASSES SPONSORED BY MR. MAY

Q. WHAT IS THE PURPOSE OF THIS PART OF YOUR TESTIMONY?

A. In this part of my testimony, I sponsor five classes of TTC costs, each consisting of affiliate and non-affiliate expenses and capital expenditures. The five classes of TTC costs that I sponsor are: the Planning and Regulatory Class; the Implementation Management Class; the System Benefit Fund Class/Renewable Energy Credits Class; the Default Service Providers Class; and the Rate/Rider Preparation Class. For each of these classes, I explain why the TTC costs in that class were necessary and reasonable, and that the price charged for the affiliate portion of this class of TTC costs to EGSI is no higher than the price charged to other affiliates for the same or similar services or items, and that the amounts charged reasonably approximate the actual costs for the service.

Q. WHAT IS THE TOTAL REQUESTED AMOUNT IN TTC COSTS FOR YOUR FIVE CLASSES?

A. The total requested amount for my five classes is $70.6 million. This overall total for all of my TTC classes combined is shown in the following:

Affiliate Costs

Group Description	Direct	Allocated	Total	Non-Affiliate Costs	Total Net Requested
Internal - Payroll / Benefits	14,575,121.74	1,575,239.32	16,150,361.07	1,377.18	16,151,738.25
Internal - All Other Internal Support Costs	68.05	-	68.05	30,659.40	30,727.45
External - Legal Contractor Costs	626,733.22	370,046.05	996,779.27	9,511,514.94	10,508,294.21
External – All Other Support Costs	16,745,242.16	3,566,028.83	20,311,270.99	18,367,358.49	38,678,629.49
AFUDC & Capital Overhead	-	-	-	5,268,407.71	5,268,407.71
Grand Total	31,947,165.18	5,511,314.20	37,458,479.38	33,179,317.73	70,637,797.11

In this table, which will be repeated below by class for each of my classes, the rows segregate costs between either "internal" or "external" groups of costs. Internal costs are costs incurred and billed by Entergy (including EGSI) personnel to a specific project. "Payroll / Benefits" is, obviously, the payroll and benefits costs of the Entergy employees' time spent on the applicable TTC projects. The "All Other Internal Support Costs" category picks up the cost of system hardware, software, and the like developed by the internal employees for TTC purposes.

The "external" costs rows are segregated between either outside (non-Entergy employee) lawyer/legal-related charges (including rate case expenses), and outside (non-legal) contractors' charges to TTC projects.

The columns are segregated between "affiliate" and "non-affiliate" costs. Affiliate costs include all non-EGSI charges; for example, TTC costs incurred by ESI. The term "non-affiliate" refers to EGSI; that is, costs incurred directly by EGSI, rather than costs billed or allocated to EGSI by an affiliate. The affiliate charges are further broken down to either direct charges or allocated charges. A "direct" charge is one in which 100% of the cost of a project is billed to EGSI and not to any other entity. An "allocated" charge is one in which a portion of a project cost is charged (allocated) to EGSI, while another portion or portion of that project cost is allocated to another entity, such as Entergy Arkansas.

Q. CAN YOU SHOW HOW MUCH IN TTC COSTS WERE INCURRED IN EACH OF YOUR CLASSES BY, FOR EXAMPLE, COMPOSITION, YEAR, OR TYPE OF COST?

A. Yes. I have attached four "alpha" exhibits to this testimony as Exhibits PRM-A, PRM-B, PRM-C, and PRM-D. These four exhibits show different views of the costs in each of my TTC cost classes.

Exhibit PRM-A is a more detailed version of the table included in the answer above. This exhibit breaks down that composite table into the group descriptions and affiliate vs. non-affiliate costs for each of my five classes.

Exhibit PRM-B shows cost information for each of my classes based on the project codes and associated billing methods that were used to compile each class.

Exhibit PRM-C shows the cost information for each of my classes by year from 1999 through 2005.

Exhibit PRM-D shows the cost information for each of my classes segregated between either a "capital" cost or an "expense" cost.

In my discussions below regarding each of my classes, I may refer back to these four alpha exhibits.

Q. IN EXHIBIT PRM-B, WHAT IS A "PROJECT CODE" AND A "BILLING METHOD"?

A. I will discuss the specific project codes and billing methods that apply to my TTC classes later in my testimony when I describe the composition of each class. As an overview, each of my classes was constructed by aggregating project codes that were related to the topic of that class. Project codes are an accounting tool used by Entergy so that employees and contractors can bill their time, expenses, and costs to a specific code that is established to capture the costs of a defined project. A project code captures the capital or expense of a specified project. Based on the nature and intent of the project, a single billing method is assigned to a project code so that the capital or expense in that project can be billed to the appropriate legal entity or entities, such as one or more of the Entergy Operating Companies (including EGSI), depending on which entity or entities benefit from that project.

Q. IN EXHIBIT PRM-D, PLEASE EXPLAIN THE TERMS "EXPENSE" AND "CAPITAL."

A. "Capital" refers to those costs associated with developing a capital asset. A capital asset is any property or equipment with a useful life of more than one year that costs $1,000 or more, or is a unit of property. For example, the costs required to design, install, and test new IT systems, or enhance existing IT systems, are capital costs.

Generally, "expenses" are those on-going costs associated with operating and maintaining Company assets; "expense" is not used to "create" the asset, as is capital.

1. <u>The Planning and Regulatory Class</u>

Q. PLEASE DESCRIBE THE TTC COSTS THAT MAKE UP THE PLANNING AND REGULATORY CLASS.

A. This class includes costs associated with the initial planning and regulatory activities in response to the large number of regulatory dockets driven by SB 7 and the subsequent planning and regulatory activities to support them. As I described earlier in my testimony, the Company's efforts to transition to competition pursuant to various Commission directives and SB 7 spanned six years and involved more than 50 separate dockets before the Commission and two dockets before the FERC. The Company's UCOS case required an enormous effort. The Company also sought approval of its BSP before the LPSC but is not seeking recovery of the expenses related to the LPSC's review of EGSI's BSP.

Q. WHAT IS THE AMOUNT OF TTC COSTS IN THE PLANNING AND REGULATORY CLASS?

A. The total amount of TTC costs in this class is $27.7 million. I have broken down this amount between affiliate and non-affiliate and internal and external in the following table: