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DOCKET NO. ______________

APPLICATION OF ENTERGY GULF STATES, INC. FOR RECOVERY OF TRANSITION TO COMPETITION COSTS	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

PHILLIP R. MAY

ON BEHALF OF

ENTERGY GULF STATES, INC.

AUGUST 2005

SUMMARY OF DIRECT TESTIMONY OF PHILLIP R. MAY

Phillip R. May is Vice President – Regulatory Services at Entergy Services, Inc. Mr. May describes the various business and regulatory activities that Entergy Gulf States, Inc. engaged in during its efforts to bring retail electric competition to the Entergy Settlement Area in Texas. The scope of that effort, which covers the period of June 1, 1999 through June 17, 2005, has cost Entergy Gulf States over $164 million, including attendant Allowance for Funds Used During Construction. Mr. May covers how these costs were necessarily incurred in response to legislative and PUC directives aimed at bringing about retail competition in the Entergy Settlement Area of Texas. Mr. May also describes in detail the management structure, as well as planning and budgeting processes employed to keep transition to competition costs in line. In addition to describing Entergy Gulf States' transition efforts in general, Mr. May also supports the reasonableness and necessity of the following specific classes of transition costs:

- Planning & Regulatory Class
- Implementation Management Class
- System Benefit Fund/Renewable Energy Credits Class
- Default Service Provider Class
- Rates/Riders Preparation Class

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APPLICATION OF
ENTERGY GULF STATES, INC.
FOR RECOVERY OF TRANSITION TO COMPETITION COSTS

DIRECT TESTIMONY OF PHILLIP R. MAY

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Phillip R. May. I am employed by Entergy Services, Inc. ("ESI") as the Vice President, Regulatory Services. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Entergy Gulf States Inc. ("EGSI" or the "Company").

Q. WHAT ARE YOUR DUTIES?

A. As the Vice President, Regulatory Services, I am responsible for providing regulatory support for EGSI's transition to competition in Texas. In addition, I am responsible for providing technical and analytical support to all the Entergy Operating Companies[1] to enable them to satisfy their regulatory obligations. My department consists of the following areas:

1. Regulatory Projects & Services
2. System Regulatory Planning & Support
3. Regulatory Strategy

[1] The Entergy Operating Companies are: EGSI; Entergy Arkansas ("EAI"), Inc.; Entergy Louisiana, Inc. ("ELI"); Entergy Mississippi, Inc. ("EMI"); and Entergy New Orleans, Inc. ("ENOI").

The Regulatory Projects and Services group monitors Entergy Corporation's ("Entergy's")[2] work on transition activities in Texas (and previously in Arkansas) and provides management with updates.

System Regulatory Planning & Support provides the analytical support to each of Entergy's various jurisdictional regulatory affairs groups in the areas of Regulatory Accounting, Revenue Requirements and Analyses, Pricing, and Rate Design and Administration. Additionally, the Regulatory Litigation Support group is part of System Regulatory Planning & Support. Regulatory Litigation Support facilitates the processes required to research answers to requests for information and other interrogatories posed by parties in various regulatory proceedings, and provides support for the physical production of regulatory filings.

The Regulatory Strategy group, which is also a part of Regulatory Services, assists Entergy's jurisdictional regulatory affairs organizations in assessing strategies for addressing issues that are pertinent to those organizations.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

[2] When I use the term "Entergy" in my testimony, I am referring to Entergy Corporation as a whole, including its regulated and unregulated affiliates and subsidiaries, which includes EGSI.

A. I have a Bachelor of Science in Electrical Engineering from the University of Southwestern Louisiana, now called the University of Louisiana at Lafayette, and a Master of Business Administration from the University of New Orleans. I also completed the Wharton School's Mergers and Acquisitions program.

I have worked for subsidiaries of Entergy for 19 years. I joined Louisiana Power & Light Company (now known to as Entergy Louisiana, Inc. or "ELI") in 1986 as an Engineer in the Rates and Regulatory Affairs department. I was responsible for developing cost of service studies to support ELI's retail and wholesale rates. I also planned and directed numerous engineering studies and special projects. In 1993, I joined the Entergy/Gulf States Utilities Merger Team as a Senior Engineer. Following that assignment, I joined ESI's Financial Planning Department and was responsible for financial planning for EGSI and ELI. In 1994, I was promoted to Senior Lead Analyst in Wholesale Transactions. In that role, I worked directly with large customers to meet their wholesale power requirements. In 1995, I was promoted to Manager of Strategic Planning. The members of my group served as internal consultants to various business units. I was later promoted to the Director of Utility Transition and Development. I was responsible for analytical and strategic analysis of the regulated utilities' transition to competition efforts. In 2000, I assumed my current responsibilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS?

A. Yes. I have testified in the following Commission proceedings: Docket No. 22356, *Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201, Public Utility Commission Substantive Rule §25.344*; Docket No. 24309, *Application of Entergy Corporation for Certification of the Southwest Power Pool as a Power Region Pursuant to PURA §39.152*; Docket No. 24336, *Application of Entergy Gulf States, Inc. for Approval of Price To Beat Fuel Factor*, and Docket No. 31315, Application of *Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider.* I also filed testimony in Docket No. 30123, *Application of Entergy Gulf States, Inc. for Authority to Change Rates and Reconcile Fuel Costs.* The Commission, however, dismissed that docket prior to hearing.

Q. DO YOU SPONSOR OR CO-SPONSOR ANY EXHIBITS OR SCHEDULES IN THIS FILING?

A. Yes, I sponsor the exhibits listed in my Table of Contents. I also co-sponsor with Company witness Chris E. Barrilleaux the project summaries that apply to my TTC cost classes. These project summaries are attached as an exhibit to Mr. Barrilleaux's testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's request for recovery of transition to competition ("TTC") costs incurred from June 1, 1999 through June 17, 2005 to implement retail open access ("ROA") in EGSI's Texas service territory. I explain how EGSI, its affiliates, and Entergy undertook and managed the transition effort. In addition, I will be providing testimony in support of the following classes of TTC costs:

- Planning & Regulatory Class
- Implementation Management Class
- System Benefit Fund/Renewable Energy Credits Class
- Default Service Provider Class
- Rates/Riders Preparation Class

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. The story of EGSI's efforts to transition from a fully regulated, traditional electric market to competitive ROA market involves many interconnected components. The transition period is a six-year period from June 1999 through June 17, 2005, with the bulk of the effort occurring from June 1999 through the summer of 2004. In the summer of 2004, the Commission decided to cease further efforts to implement ROA in EGSI's Texas service territory (also referred to as the "Entergy Settlement Area in Texas" or "ESAT").

During this six-year transition period, significant, complex systems were being planned, developed, tested and implemented in anticipation of ROA. However, as Company witness Joseph F. Domino also addresses in his testimony, EGSI was not able to transition to ROA as ERCOT did in 2002. Instead, the Company continued to expend considerable resources and dollars towards an uncertain date for ROA. These efforts continued until finally, by vote in June 2004, followed by a written order in July 2004, the Commission decided that it would not continue to require that EGSI pursue ROA until an appropriate "Independent Organization" was in place.

The pursuit of ROA was an enormous undertaking. I will explain in more detail the projects internal to EGSI and ESI to plan, implement, and maintain these efforts. I will also describe the major public proceedings convened before the Commission to address both state-wide and ESAT-specific ROA. These public efforts involved: rulemaking projects; contested cases to set rates for what would become the "wires" companies that would be "unbundled" from the regulated electric utilities, as well as the unbundling plans themselves; and ESAT-specific contested case dockets that addressed whether ESAT should proceed to ROA, what types of market rules, also known as "ESAT Protocols," should be in place for both the retail and wholesale markets in ESAT, and whether an "Independent Organization" could or should be put in place under what was referred to as an "interim" solution for ESAT. Commencing in June 2001, in accordance with Commission rules, EGSI was also subject to the

Customer Choice Pilot Project (referred to as the "pilot"), in which a limited number of customers would be able to switch from traditional bundled electric service to unbundled ROA service. The pilot was essentially a test for ROA. EGSI remained subject to this pilot readiness requirement until July 2004, and actually had a few customers who did "switch" to other electric providers for a short time in late 2003 to May 2004.

While these projects and contested dockets, and the pilot, were progressing, state-wide rules were being developed and revised to handle the transactions among the new ROA stakeholders, including the retail customers, the "wires" companies, the Retail Electric Providers ("REPs"), and the Electric Reliability Council of Texas ("ERCOT") which served as the state-wide "registration" agent that would be in charge of making sure that retail customers could switch from provider to provider without interruption of electric service. These state-wide rules—referred to as "Standard Electronic Transaction" (or "SET") rules—changed many times over the course of EGSI's transition. As these SET rules changed, EGSI had to remain compliant with the then-effective SET version, both for purposes of moving to full ROA in the then-anticipated near-term, and for the pilot.

In my testimony, I will attempt to convey not only the enormous magnitude of the work necessary for these transition efforts and obligations, but also show that we had to rely heavily on outside resources to assist us in doing so. EGSI (and ESI) had not previously been through this type of an effort. We needed the expertise and experience of outside consultants and lawyers to help us plan and understand the work needed to accomplish ROA. We also needed the personnel resources of outside vendors—including consulting and law firms—to prepare and implement the plans, systems, and necessary regulatory filings.

In short, I attempt to convey the magnitude of the necessary effort and the changing assumptions and expectations. This requires that I explain in some detail the technical aspects of what we were doing, and why. When I provide those explanations, I will reintroduce the concepts, and acronyms, that I have summarized in this overview. By going into this level of detail, I will also explain why the overall TTC costs incurred by EGSI, including the specific TTC costs that I sponsor, were reasonable and necessary.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section II, I provide a more detailed overview discussion of the reasonableness and necessity of the $164 million in Total Net Requested TTC costs incurred as of June 17, 2005. This $164 million includes attendant Allowance for Funds Used During Construction accrued through June 17, 2005.

In Section III, I discuss and support the specific classes of transition costs that I sponsor: the Planning and Regulatory Class; the Implementation Management Class; the System Benefit Fund Class; the

Default Service Providers Class; and the Rates/Riders Preparation Class. I also discuss the pro forma adjustments to the TTC costs that I sponsor.

I conclude my testimony in Section V.

II. RECOVERY OF TTC COSTS

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this Section II, I first provide evidence of the reasonableness of the overall level of EGSI's TTC costs of $164 million incurred as of June 17, 2005. In this discussion, I explain: the transition decision architecture and how it responded to the challenges of preparing for ROA, including delays in reaching ROA; the TTC budgeting process; and the annual TTC spending trends, by year, for the TTC recovery period. I explain how the TTC costs were "captured" in projects and then, to the extent billed by affiliates to EGSI, how the allocated or assigned portion of the Texas portion of those costs were billed to the Texas jurisdictional portion of EGSI ("EGSI-Texas"). The "Total Requested Amount" in this docket represents the TTC costs attributable only to EGSI-Texas, and not to other affiliates or EGSI-Louisiana. This assignment assures that the TTC costs—which were incurred for Texas and not Louisiana—are recovered from Texas, and not Louisiana, customers. I then describe the method used to allocate the EGSI-Texas costs to the various Texas rate classes.

To graphically describe the Total Requested Amount of TTC costs that EGSI seeks to recover through this filing, I have attached as Exhibit

PRM-1, a chart titled "TTC Foundation Chart," which I also reproduce below. This Foundation Chart shows the total TTC costs by witness and by cost category as of June 17, 2005, including the attendant Allowance for Funds Used During Construction. The cost "categories," which are groups of similar TTC cost classes, are identified on the right side of the Foundation Chart. The cost categories are: "Plan, Develop Rules & Business Support;" "Design, Build, Test, Pilot & Maintain Systems;" "Other SB 7 Requirements;" and "Rate Filing Costs." This chart is also attached as an exhibit to the testimony of Company witnesses Domino and Vikki G. Cuddy.

TTC FOUNDATION CHART

Witnesses		General Category of Cost
Phillip May	PLANNING AND REGULATORY $27.7MM	Plan, Develop Rules & Business Support $43.3MM (26%)
	IMPLEMENTATION MANAGEMENT $15.6MM	
Tom Manasco	TEXAS SET AND LOAD PROFILING AND DATA AGGREGATION $46.5MM	Design, Build, Test, Pilot & Maintain Systems $101MM (62%)
	PILOT OPERATIONS $11.1MM	
	PILOT PROJECT $0.8MM	
Bill Craddock	TEXAS DISTRIBUTION CCS $13MM	
Phillip May	DEFAULT SERVICE PROVIDER $13.6MM	
Andy Quick	CUSTOMER SERVICE $8.6MM	
	LOAD FORECASTING $3MM	
	RETAIL SET $2.5MM	
	TRADING AND RISK MANAGEMENT $1.9MM	
Phillip May	SYSTEM BENEFIT FUND/ RENEWABLE ENERGY CREDITS $7.4MM	Other SB7 Require-ments $13.6MM (8%)
Karen Radosevich	ENERGY EFFICIENCY PROGRAMS $6.2MM	
Phillip May	RATES/RIDERS PREPARATION $6.3MM	Rate Filing Costs $6.3MM (4%)

TOTAL
$164.2MM

I have also attached as my Exhibit PRM-2 a summary spread sheet that compiles the individual items of TTC costs (including Allowance for Funds Used During Construction) through June 17, 2005, by witness and by class of cost. For the reader's convenience, this chart is also attached below:

<u>Overall TTC Costs By Witness/Class</u>

TTC Witness	Class	Total
Phillip May	Default Service Provider	13,620,866
	Implementation Management	15,596,835
	Planning & Regulatory	27,686,716
	Rates/Riders Preparation	6,297,413
	SBF & RECs	7,435,967
Phillip May Total		70,637,797
Tom Manasco	Pilot Operations	11,100,246
	Pilot Program	780,935
	Texas SET & LPDA	46,534,136
Tom Manasco Total		58,415,316
Andy Quick	Customer Service	8,623,377
	Load Forecasting	2,974,560
	Retail SET	2,558,636
	Trading and Risk Management	1,865,119
Andy Quick Total		16,021,692
Bill Craddock	Texas Distribution CCS	12,959,628
Bill Craddock Total		12,959,628
Karen Radosevich	Energy Efficiency Programs	6,205,676
Karen Radosevich Total		6,205,676
Grand Total		164,240,109

A. <u>Overall Reasonableness and Necessity of EGSI's TTC Costs</u>

Q. IS THE LEVEL OF EGSI'S TTC COSTS REASONABLE?

A. Yes. The extensive processes that were established to manage the transition to competition and monitor and control TTC costs provide assurance that the TTC costs for which EGSI seeks recovery were not only reasonable, but also necessary. A chronological summary of EGSI's TTC efforts and the corresponding trend of TTC costs provide assurance that the amount of TTC costs for which EGSI seeks recovery is reasonable. As addressed in the testimony filed by Company witness Cuddy, EGSI's TTC costs are reasonable when compared to what one would expect to spend to manage and implement retail open access in a market over an extended period. Company witness Dennis L. Thomas also provides an external expert opinion on the reasonableness of the TTC costs, based on an analysis of the management and cost controls that applied to the TTC cost classes.

Q. WAS INCURRENCE OF THESE TTC COSTS NECESSARY?

A, Yes. All of these costs were incurred to comply with Senate Bill 7 and the Commission's rules and orders issued to implement that law. Company witness Domino explains what these requirements and efforts entailed. Other Company witnesses also explain in more detail specifically why their classes of costs represent both reasonable and necessary TTC costs. Put simply, until mid-2004, EGSI was required by statute and the Commission to implement ROA in its Texas service territory. EGSI's incurrence of these costs was not only necessary, but also a legal requirement.

1. <u>Management of TTC Costs</u>

Q. WHAT IS THE PERIOD OVER WHICH THE TTC COSTS WERE INCURRED?

A. The period over which the TTC costs were incurred—the "TTC cost period"—is June 1, 1999 through June 17, 2005. The Texas ROA legislation was enacted through Senate Bill ("SB") 7, which the Texas Senate and House both voted to pass on May 29, 1999. Then-Governor Bush signed SB 7 into law on June 18, 1999, with an effective date of September 1, 1999. But, because SB 7 was a complex piece of legislation that required utilities and others to comply with numerous unique provisions, EGSI and Entergy began work immediately on implementing ROA. The end date for the TTC cost period is June 17, 2005, because the legislation that authorizes EGSI to file for recovery of its TTC costs—House Bill ("HB") 1567—became effective when it was signed by Governor Perry on June 18, 2005. HB 1567 allows EGSI to file for recovery of TTC costs "made or incurred" before the effective date of that bill. Therefore, the end-date for the TTC cost period is the day before the effective date of HB 1567.

Q. WAS THE TRANSITION TO COMPETITION ACTIVELY MANAGED BY EGSI AND ITS AFFILIATES THROUGHOUT THE TTC COST PERIOD?

A. Yes. To ensure proper management, the structure and scope of work developed to manage TTC costs evolved over time as the circumstances changed. Initially, ESI's Financial Planning Department coordinated and managed the Company's transition efforts up to the time that electric deregulation legislation became a reality in both Texas and Arkansas by June 1999. The Company is not requesting any costs incurred prior to June 1, 1999.

At that time, EGSI and the other Entergy Operating Companies recognized the extensive nature of the changes that would be necessary to prepare their utility operations for retail competition. As a result, a Transition Management organization was created and staffed to coordinate and manage the overall efforts in preparing for retail competition.

I emphasize that there were a lot of "moving parts" throughout this process commencing in 1999. EGSI had not gone through anything like the restructuring and unbundling required by SB 7. As I explain below and as is also explained by Company witnesses Thomas R. Manasco, William T. Craddock, and Andrew E. Quick, the restructuring process was not solely managed by the Texas portion of EGSI—nor could it be, given the extensive nature of change required and the central support services structure that provides many support services from ESI to all of the Entergy Operating Companies, including EGSI, and the federal and other retail regulators that also had jurisdiction over various aspects of EGSI's operations. In addition, during 1999 and 2000 Entergy was also managing the transition to ROA in Arkansas as well as Texas and was seeking to leverage the activities required by the two initiatives to achieve more efficiency. As explained below, the TTC management structure evolved over time, and was particularly affected by the requirement to separate the Texas jurisdictional portion of EGSI into regulated and (soon to be) unregulated operations and services, as well as the continuing Commission-ordered delays in reaching ROA.

Q. HOW DID THE MANAGEMENT STRUCTURE CHANGE AFTER THE TEXAS SENATE AND HOUSE PASSED SB 7?

A. In June 1999, a new organization was formed—Transition Management—to oversee transition to competition activities. As stated above, EGSI (and Entergy) began work in mid-1999 to comply with SB 7. The initial work was developing a thorough understanding of what was required as a result of restructuring and then implementing those requirements. Among other things, work started immediately on the preparation of the "Business Separation Plan" and "Unbundled Cost of Service" filings that were required to be filed on January 10, 2000 and March 31, 2000, respectively. I discuss these and other filings in more detail later in my testimony.

Q. PLEASE DESCRIBE THE TRANSITION MANAGEMENT ORGANIZATION.

A. Transition Management focused on preparing EGSI and EAI for retail competition. Those efforts in Arkansas continued until activities slowed there in late 2000 and ultimately stopped in early 2001 when legislation delayed and then terminated ROA efforts in that state. The responsibilities of this team included the overall coordination and management of all initiatives related to retail competition. These included project management, implementation of processes and systems necessary to support ROA, coordination of compliance with regulatory and legal requirements including rate or informational filings, and participation in rulemaking projects.

Three functional areas comprised Transition Management. The first functional area concentrated on implementation. Particular emphasis was on preparing for the retail pilot that was to begin in Texas on June 1, 2001. This implementation focus required the coordination of the Retail and Distribution Decision Boards, management groups which I will discuss below, and on the overall readiness of people and processes with responsibilities that included assessment and redesign of business processes and systems, employee training and communication, and transition cutover and contingency planning.

Transition Management's second functional area focused on the effective integration of planning and decision-making for the Power Supply, Transmission, and Restructuring Decision Boards, which were also key TTC management groups that I will discuss in detail. This included coordinating the development of business unit plans to support spending decisions, providing decision support for those functional decision boards and teams, participating with decision teams, and coordinating the development and tracking of overall transition spending.

Transition Management's final functional area focused on coordinating the regulatory activities related to transition. This included planning for and implementing the operating model for the unbundled companies. Activities included development of appropriate unbundled rates, defining competitive services and the impacts of removing such services from the regulated cost structure and, until mid-2002, the administration, coordination, and training aspects of the Texas affiliate rules. This latter function moved in 2002 into a new Corporate Compliance group.

Q HOW WAS THE OVERALL TRANSITION TO COMPETITION MANAGED?

A. Transition Management established a decision architecture to provide dedicated senior leadership, focus on key transition issues, and enhance timely decision-making and decision quality. This architecture was implemented by the creation of "Decision Boards" and "Decision Teams" for the purpose of planning and implementing the legislative mandates required by SB 7 (and also initially Arkansas's Act 1556). Ensuring an integrated approach to addressing issues across each decision board was the responsibility of Transition Management, which participated in all functional decision board meetings and ensured that the decisions made were integrated into an overall plan enabling a successful implementation of transition processes.

At the time of the establishment of this architecture in 2000, the initial work to comply with SB 7 and Act 1556 was underway and senior management anticipated that other of Entergy Operating Company jurisdictions might follow suit and eventually move to implement ROA. Therefore, as a multi-jurisdictional utility company, this architecture had to address the transition activities of the jurisdictions moving to competition as well as acting to mitigate the impact of such activities on the jurisdictions that remained regulated. *See* Exhibit PRM-3 for a graphical representation of this architecture.

Q. PLEASE DESCRIBE EXHIBIT PRM–3.

A. There are three levels of responsibilities and activities shown in this exhibit. At the highest level, the TTC Decision Board gave final approval to the overall planning and direction of efforts in transitioning to competition. The members of this decision board included the Chief Executive Officer, the Chief Financial Officer, and other senior executives of Entergy, including the senior leadership of Transition Management. In addition, Transition Management retained the services of an outside expert from the NorthBridge Group as an active participant on this board.

The TTC Decision Board met as needed. In 2000 and 2001, the Board met approximately once each month.

At the next level, several functional Decision Boards were established. Each board represented a functional area whose business practices would be altered as a result of ROA. These functional boards' leadership structure consisted of co-leads, the senior officer of Transition Management and the senior officer of the particular functional area of focus. Additional members of these boards included executives from other functions that would be impacted by the transition to competition. The functional Decision Boards were as follows:

- the Power Supply and Wholesale Marketing Decision Board;
- the Transmission Decision Board;
- the Restructuring Decision Board;
- the Retail Decision Board; and
- the Distribution Decision Board.

Q. DESCRIBE THE ROLE OF THE POWER SUPPLY AND WHOLESALE MARKETING DECISION BOARD.

A. The Power Supply and Wholesale Marketing Decision Board addressed issues related to the formation of wholesale markets, protocols for the operation of the markets, and the ultimate disposition of generation assets.

Q. DESCRIBE THE ROLE OF THE TRANSMISSION DECISION BOARD.

A. The Transmission Decision Board dealt with issues involving the development of a competitive wholesale market that involved the Entergy Operating Companies' integrated transmission system, such as the development of wholesale market protocols, review of the rules and rates for transmission access, and, initially, the development of a stand alone transmission company—generically called the "Transco."

Q. DESCRIBE THE ROLE OF THE RESTRUCTURING DECISION BOARD.

A. The Restructuring Decision Board dealt with the issues related to EGSI business processes and functions that would have to be modified, rebuilt, or created to accommodate ROA. The statutory requirement of SB 7 that the Company unbundle created a myriad of issues that this board and its leadership sought to address. This included the development of a comprehensive Business Separation Plan—"BSP"—to address legal and financial requirements. In EGSI's case, the BSP required the division, along state lines, of EGSI's operations between Texas and Louisiana, in addition to unbundling EGSI's Texas operations, so that EGSI's Louisiana operations, subject to the retail jurisdiction of the Louisiana Public Service Commission ("LPSC"), could continue to operate as a regulated utility.

This board also had responsibility for assessing all changes to business infrastructure necessary for ROA. For example, this board considered what legacy computer systems would have to be modified to accommodate the new structure of the retail electric service market.

Q. DESCRIBE THE ROLE OF THE RETAIL DECISION BOARD.

A. The Retail Decision Board focused on creating a retail affiliate (or affiliates) that met the requirements of SB 7 to serve as the "Price To Beat" ("PTB") Retail Electric Provider (REP) in EGSI's Texas service territory. Over time, stakeholders began to refer to EGSI's Texas service territory as the "Entergy Service Area in Texas" or "ESAT." The Retail Decision Board also focused on establishing an Entergy REP that could also serve the *non*-PTB loads both inside and outside of ESAT, and an Entergy "Provider of Last Resort" ("POLR") REP who would be necessary, in accordance with SB 7, to serve another "class" of customers who were "dropped" by their initial REPs.

Q. DESCRIBE THE ROLE OF THE DISTRIBUTION DECISION BOARD.

A. The Distribution Decision Board focused on the existing distribution organization and started implementation planning and development of an unbundled distribution "wires" company, referred to generically as Entergy Texas Distribution. This board also faced the issues common to starting a new business. One of its most significant projects was its evaluation of new computer systems, such as Distribution Market Mechanics, which had to be designed, tested, and implemented.

Q. EXHIBIT PRM-3 IDENTIFIES A THIRD LEVEL IN THE DECISION ARCHITECTURE. PLEASE DESCRIBE THIS LEVEL.

A. The third and last level in the new decision architecture involved the formation of Decision Teams. These teams followed the same functional alignment as the Decision Boards described above. Each team was comprised of members from the appropriate business units. By business units I mean the functionally separate portions of the integrated utility business; for example: fossil generation, transmission, distribution, etc. Members had to be subject matter experts, possess a thorough understanding of the business issues, had to have a strong analytical ability, and had to be action-oriented.

These teams formulated the ideas and created the plans necessary to support operations in the competitive retail market. These teams also implemented the processes that would be used in and necessary for that market. Generally, a Decision Team would develop a plan or a project necessary for operations in the competitive retail market. The Decision Team would then bring that project to its respective Decision Board, which was responsible for approving, modifying, or denying requests to go forward with the plan or project. For major decisions, such as the major elements of the Company's BSP, the TTC Decision Board would review the recommendation of the appropriate Decision Board(s).

Q. WHAT WAS THE ROLE OF THE "INTEGRATION TEAM" REFERENCED IN EXHIBIT PRM-3?

A. The Integration Team had responsibility to address issues that spanned teams and for the overall implementation management of the TTC efforts. Generally, the Integration Team members were part of Transition Management. Members participated with Decision Teams in meetings and also attended Decision Board meetings. By participating in the process of planning and implementing various projects, the members of Transition Management were able to stay abreast of issues and were better able to oversee and coordinate the Company's overall TTC efforts.

Q. DID THE COMPOSITION OF THE DECISION BOARD AND DECISION TEAMS CHANGE OVER TIME?

A. Yes. The members of the Decision Teams and Decision Boards changed over time, but the overall system of review established in the decision architecture remained the same. The membership changed as people were promoted or assigned new responsibilities. When that happened, new members were assigned to participate in the Decision Board or Decision Team. As discussed previously, the Decision Boards included executives from those functions that would be impacted by the transition to competition; the Decision Teams were populated with appropriate subject matter experts from the business units.

Q. HOW LONG WERE THESE BOARDS AND TEAMS IN PLACE?

A. The Decision Boards were never officially disbanded, instead, the Decision Boards met on an as needed basis and as much of the decision making concluded, these Boards simply no longer met. Decisions Teams, on the other hand, had lives that were specific to the particular tasks with which these teams were assigned. These teams were disbanded as assignments were completed and, as the delays in ROA continued beyond January 1, 2002, they were either significantly reduced in operations or simply ceased.

Q. DID THIS DECISION ARCHITECTURE SUPPORT PRUDENT MANAGEMENT OF TTC COSTS?

A. Yes. The decision architecture supported the prudent management of TTC costs because it imposed a disciplined management structure with multiple layers of control and review of TTC costs. The Decision Teams were not free to initiate projects and incur costs without approval from the Decision Boards. The Decision Teams were not free to modify a project and thereby incur additional costs without approval from the Decision Boards. The Decision Teams were accountable to the Decision Boards. The Decision Boards were accountable to the TTC Decision Board. But this structure did not inhibit flexibility or responsiveness. Rather, it established a reasonable management structure that placed overall direction at the TTC Decision Board, with implementation and problem resolution handled first, if possible, at the Decision Team and Decision Board levels.

Q. DID THE DECISION ARCHITECTURE CHANGE IN RESPONSE TO DELAYS IN THE COMMENCEMENT OF RETAIL OPEN ACCESS?

A. Yes. The decision architecture did change in response to changes in the pace and scope of ROA implementation activities; however, the conceptual basis consisting of a hierarchy decision-making processes described previously remained unchanged. For instance, the role of the Power Supply and Wholesale Marketing Decision Board diminished as key assumptions, rules, or protocols affecting wholesale markets became better known. This shifted the focus from the Decision Board to the Decision Teams that worked on implementing the particular market design. There were similar shifts toward implementation efforts as more information became known about the retail market design. This affected both the Retail and Distribution Decision Teams. When procedural delays were encountered, such as in late 2001 when the Commission ruled that EGSI's Texas service territory would not proceed to ROA on January 1, 2002, EGSI began at that time to ramp down its efforts to account for the delay in ROA for ESAT. But, as explained later in my testimony and in the testimony of Company witnesses Domino, Manasco, and Quick, work efforts did not stop completely because, until June 2004, EGSI was operating under the expectation that ROA would commence in the near term—roughly within one year from any given point in time. So the Company had to stand ready to move to ROA on potentially relatively short notice and, in any event during that period, stand ready to serve as the "wires" company for any customers who switched to non-affiliated REPs during the then-ongoing retail pilot project.

The structure also changed in other ways. Initially, a myriad of decisions had to be made across a broad set of functional areas affecting various business processes. This was particularly true as the Commission rulemakings and accompanying ERCOT retail protocols required a number of changes to "Texas Standard Electronic Transactions" ("SET"), which are the standardized computer communications processes utilized for purposes of managing retail customer information, and customer switching, among REPs. These rulemakings and retail protocol changes continued until well after January 1, 2002. Company witness Manasco describes the numerous, ongoing changes to Texas SET in his testimony. The SET revisions (and ongoing changes to market rules) mandated large systems and process changes for Investor Owned Utilities, Transmission and Distribution Utilities (that is, the unbundled "wires" companies), REPs, other stakeholders including merchant and unbundled generation companies, and ERCOT. The rapid pace of rules development required frequent interaction among the Decision Teams and the Decision Boards. Again, as key decisions were finalized, the Decision Teams and Decision

Boards began to meet less frequently and the focus shifted to implementation of a particular project.

Within Transition Management, this shifting scope of work led to organizational realignments to better focus on the work at hand. For example, the early focus on designing and planning later shifted to a focus on implementing and testing, which resulted in specific organizational changes recognizing this shift. Specifically, between 1999 and 2002 Transition Management services reduced the resources focused on planning and decision support by trimming the employees within that organization from four to just one. Furthermore, implementation resources were shifted to the specific business units responsible for implementation, and Transition Management implementation resources shifted from 13 to just two. In other words, Transition Management adapted to meet the specific requirements of the Company's transition efforts.

Finally, as mentioned above, Transition Management orchestrated "ramp downs" in response to ongoing uncertainty with regard to the commencement date for ROA. While the Company maintained an appropriately staffed and practicable plan for achieving ROA in the September 2002 to January 2003 timeframe, as initially contemplated in the Commission's order in Docket No. 24469 that delayed ROA in ESAT, the Company also recognized that this level of internal and external resources was not an efficient utilization of resources during periods of uncertainty regarding the date for commencement of ROA. EGSI, through the Decision Teams, therefore initiated ramp downs to manage its costs. This strategy consisted of minimizing the Company's use of outside contractors and reducing its internal staff to the minimum level necessary to monitor rule changes, maintain pilot readiness, and continue with the projects and contested cases before the Commission that dealt with transition issues. This reduced staff also maintained a "ramp up" plan that would still allow the Company to implement ROA within a specified target date.

During the ramp down periods, a select group of subject matter experts, along with our regulatory and legal teams, remained very active to address various dockets driven by the Commission with the aim to achieve ROA in ESAT.

Q. DESCRIBE THE FINANCIAL PROCESSES THAT WERE USED TO PLAN, MONITOR, AND CONTROL TTC COSTS.

A. The approach to managing and controlling costs for the Company's (and initially Entergy Arkansas, Inc's. ("EAI's") early transition efforts leveraged existing processes. First, the Company has a set of existing policies that deal with financial and accounting issues. These policies address such issues as establishment and approval of capital projects, budgeting, travel, and expenses. These policies were applicable to the Company's transition efforts. Second, a specific set of project codes (both capital and expense) were established to capture costs associated with the

Company's efforts. Company witness Barrilleaux discusses in more detail how project codes are used to track costs for various activities. Third, major implementation projects and their associated costs were identified and rolled up into a transition budget. At the outset, these estimated costs were designed to address the Company's efforts in multiple jurisdictions. During 2001, Texas became the only remaining jurisdiction with ongoing ROA-related activities. Accordingly, the budget began to reflect only the remaining Texas projects. Fourth, budget reports were prepared on a monthly basis and reviewed with senior management. I discuss these budget reports later in my testimony. Business units were expected to meet both project spending targets and schedule targets. Progress was monitored by Transition Management and by existing monthly budget reporting and variance management processes.

Q. HOW WERE THE MONTHLY BUDGET REPORTS DEVELOPED?

A. Transition Management coordinated the development of monthly analyses of spending versus budget within the various business units involved with transition implementation. The affected business units, senior management, and I reviewed these reports on a monthly basis. Approximately quarterly, Transition Management prepared a summary of transition activities and similar budget analyses for the Finance Committee of the Entergy Board of Directors. Later, Transition Management directed these reports to the Audit Committee of the Entergy Board of Directors.

Q. WHAT APPROACH DID TRANSITION MANAGEMENT TAKE TO MANAGING TTC COSTS?

A. Initially, Transition Management took primary responsibility for developing the TTC budget. In the spring of 2000, Transition Management developed an estimate of the TTC budget for the years 2000 through the end of 2001, anticipating implementation of ROA on January 1, 2002. Transition Management developed the budget by asking each of the various business units involved in the transition effort to estimate their incremental needs during the coming year. The term "incremental" was used to describe the incremental spending on outside attorneys, consultants, additional personnel, equipment, and systems caused by the legislation authorizing ROA, as opposed to the base level of spending for the salary, benefits, expenses of existing employees, and ongoing expenses budgeted by the respective business units to support ongoing utility operations. Consistent with this approach, the operating budget view, called "Responsibility View," reports were used. The responsibility view reports reflect dollars that are under more direct control of the operating unit. They do not include corporate overheads, payroll loaders/benefits, or Allowance for Funds Used During Construction ("AFUDC") that are a part of full financial view reports for accounting purposes. The Company's TTC request is based on the full financial view, rather than the less-inclusive "responsibility" view.

Q. HOW DID TRANSITION MANAGEMENT ASSESS THE REASONABLENESS OF THESE PROJECTIONS?

A. In late 1999, Transition Management asked Accenture, then known as Andersen Consulting, to research and share information on the range of transition implementation costs estimated by other utilities that had retained Accenture in those efforts. Accenture reported a possible range of estimates, but did not share any specific information about other the utilities due to confidentiality agreements. Accenture's information confirmed that the Company's high-level budget estimate was reasonable. I discuss these estimates later in my testimony.

Q. WAS DIRECT RESPONSIBILITY FOR MANAGING THE SPENDING ON TRANSITION IMPLEMENTATION CHANGED AT SOME POINT?

A. Yes. At the same time as Transition Management was coordinating the overall budget estimates with each of the business units, it also transferred primary responsibility for the TTC budgets to the business units (*e.g.*, Distribution) responsible for executing implementation within their own areas of responsibility. This transfer enhanced the link between transition implementation and the accountability for transition spending. Accordingly, each business unit and jurisdiction would execute transition projects for which it was responsible, spend funds as necessary and reasonable, and report actual TTC spending versus the TTC budget within the normal process of cost control and monitoring.

Transition Management also established specific protocols to address variances from the TTC budget. For example, if budget analysis indicated that projected costs might exceed the budget levels established by the business units, the jurisdictional president, or the business unit leadership responsible for the variance, would have to seek approval from Transition Management to maintain such spending levels.

Thus, three levels of monthly cost control and monitoring existed for TTC costs: at the business unit's leadership level; at the jurisdiction president's level; and at the system-wide level (ESI and EGSI, for example) by Transition Management.

Q. DO YOU HAVE ANY DOCUMENTARY EVIDENCE THAT DETAILS THESE BUDGETING AND BUDGETING VARIANCE PROCESS?

A. Yes. I have attached as my Exhibit PRM-4 copies of TTC budget reports, and variances, for the months of June and December 2000, February and December 2001, and January and October 2002. These budget reports were compiled by my organization. The reports demonstrate that the budgets and budget reviews were in place. June 2000 is the first month in which these budget reports were compiled. We stopped compiling these reports at this level in late 2002 because, by that time, much of the initial implementation work had already been done and, going forward, the costs were incurred to either maintain systems in anticipation that ROA would commence in the near term, or to upgrade systems and processes, such as Texas SET, as new versions of those processes were required to remain compliant with the evolving and anticipated market. Nonetheless, this spending remained closely budgeted and monitored by each of the individual business units and was periodically reviewed by Transition Management.

Q. DID THE TTC BUDGET CHANGE OVER TIME?

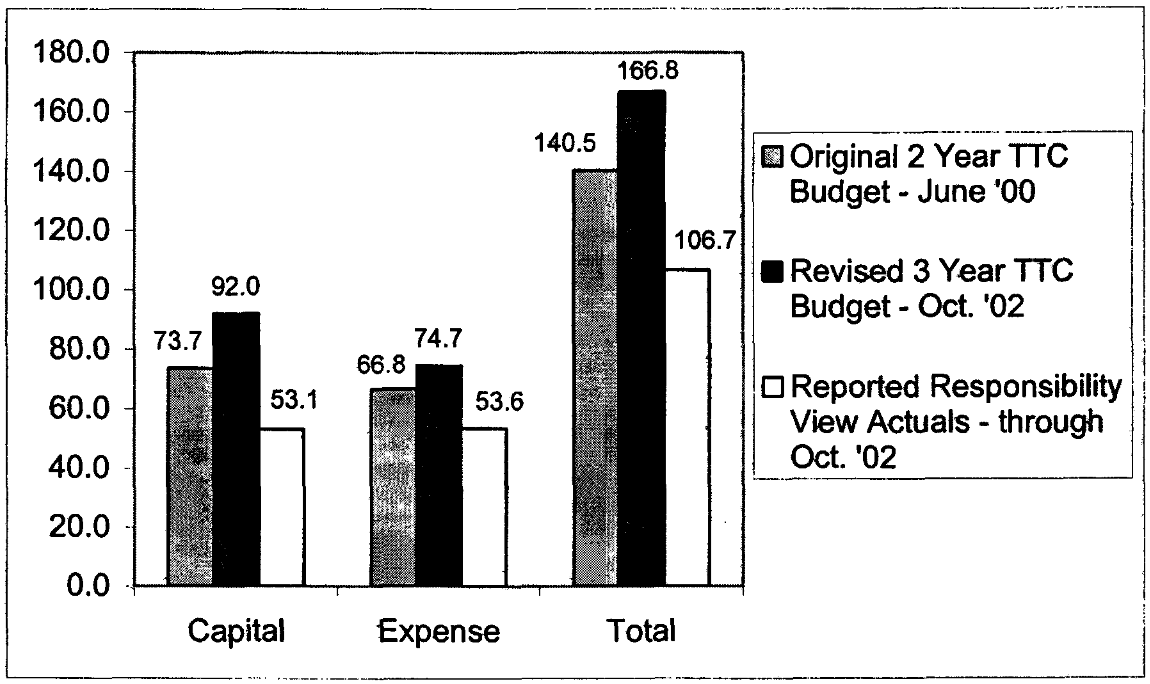
A. Yes. As I described earlier, we verified our initial high level budget numbers with a knowledgeable source, Accenture, but the budget had to be developed without an understanding of the full market design and impact of that design. Also, the initial budget was established only for implementation through 2001.

The initial two year budget of $140 million was adjusted on a periodic basis as the market changes continued and the timeframe for Entergy's ROA date continued to be delayed. At the time Transition Management ended the reports in October of 2002, the budget was $167 million.

Q. HOW DID THE TTC ACTUALS COMPARE TO ITS BUDGET?

A. TTC costs as reflected in these reports show that the transition effort spent (or incurred) was less than was budgeted. The resulting under-budgeted costs were due, in part, to the major ramp down the Company undertook to conserve expenditures until an ROA start date became more certain. However, to be clear, the purpose of these reports was to establish a method to monitor incremental spending; they were not intended as a means to compare total spending to an estimated budget as is typical in a large project where the requirements are well known. Nevertheless, these reports were a valuable tool to support Transition Management's overall monitoring, coordination, and implementation of transition projects.

TTC BUDGET VS. SPEND REPORTS (through Oct. 2002) (in millions)



Q. WHY ARE THERE VARIANCES BETWEEN THE BUDGETED AMOUNTS AND THE AMOUNTS ACTUALLY SPENT?

A. There are instances in the reports in which we spent more within a particular business unit than was budgeted. Keep in mind that the initial TTC budget had to be set with little to no detailed information about the market design. These were high level budgets based on our best estimates at the time. We had some idea of the enormity and scope of the entire transition process but we had no direct experience that would provide the basis for an accurate estimate of the cost to unbundle, develop completely new business processes and build/test systems to support the ROA market.

A prime example of why we had variances between what we budgeted and what we spent is the process used to develop the standardized computer communications processes utilized for purposes of managing retail customer information and customer switching among REPs; that is, Texas SET. The development of these processes was extremely complex, and unforeseen and continuous changes compounded the cost impact to EGSI. Company witness Manasco describes the costly impact of the market design and those market changes in more detail in his testimony.

Q. REGARDING THE BUDGETS, WHAT OTHER CHANGES WERE IMPLEMENTED TO ENSURE SOUND MANAGEMENT OF TRANSITION RESOURCES?

A. Commencing in 2000, the number of project codes utilized in tracking TTC expense costs was expanded to more accurately reflect how the costs would be assigned to or allocated among the operating companies or jurisdictions. This information was reflected in the first three or four letters of the project code as shown in the table below. I will explain the "acronym" basis for these project codes below. The reason I am explaining these codes here is because you will see references and detailed discussions of individual project codes later in my testimony, as well as in the testimony and/or exhibits of Company witnesses Manasco, Quick, Barrilleaux, Craddock, and Karen R. Radosevich. Essentially, the following is a primer on the basic structure of the project codes for expense (as distinct from capital) costs. These codes were structured in the following manner;

- 1st letter – always "T" for transition
- 2nd letter – "R" designates recoverable and "N" designates non-recoverable work. Non-recoverable costs involved work supporting the non-default service provider retail effort, but also included other activities such as competitive strategy. These guidelines are discussed in more detail later in my testimony.

- 3rd/4th letters - these two letters were used to identify jurisdictions involved and billing method. "GT" designated solely for the Texas portion of EGSI, "GL" designated solely for the Louisiana portion of EGSI, "CO" and CC" designated the shared costs with Entergy Arkansas, Inc., "AL" designated for all jurisdictions, and "J" designated narrowly defined amounts for all jurisdictions with limitations on recoverable work designated by the Arkansas Public Service Commission.

TTC Project Code Prefixes

Initial Letters of TTC Project Code	Recoverable?	Assignment or Allocation
TRGT__	Yes	100% to EGSI's Texas jurisdiction
TNGT__	No	100% to EGSI's Texas jurisdiction
TNGL	No	100% EGSI's Louisiana jurisdiction
TRCO__	Yes	Based on relative number of electric customers of Entergy Arkansas, Inc. and of EGSI's Texas jurisdiction (65.4% EAI/34.6% TX)
TRCC__	Yes	Based on relative number of electric customers of Entergy Arkansas, Inc. and of EGSI's Texas jurisdiction (65.4% EAI/34.6% TX)
TNCO__	No	Based on relative number of electric customers of Entergy Arkansas, Inc. and of EGSI's Texas jurisdiction (65.4% EAI/34.6% TX)
TRAL__	Yes	ESI Billing Method 35 or ESI Billing Method 23 depending on the specific TTC activity

TRJ___	Yes	ESI Billing Method 35 or ESI Billing Method 23 depending on the specific TTC activity
TNAL__	No	ESI Billing Method 35 or ESI Billing Method 23 depending on the specific TTC activity

The final two letters in the project code identified the activity associated with the project code, as shown in the table below.

TTC Project Code Suffixes

TTC ACTIVITY	DESCRIPTION
IM	Implementation Management
UB	Unbundling
CS	Competitive Strategy (Non-Recoverable)
RM	Rule Making
SA	System Agreement
SC	Stranded Cost
CE	Customer Education
CI	Customer Interface
SV	Employee Related Costs (*e.g.* Severance, Retraining, etc)
TI	Transco Implementation

Combining these letter series, each project code had a specific meaning to an employee entering his or her time or to the manager reviewing an employee's time sheets. For example, the Project Code TRGTUB signifies work related to unbundling EGSI as required by SB 7 and, as such, is appropriate for recovery and is assignable to EGSI's Texas jurisdiction.

Capital projects required for the transition were also subject to Entergy's existing policies and guidelines. TTC capital projects focused on the systems and systems changes required to support the retail market model in Texas, including Texas SET, load profiling and data aggregation, and Customer Information System changes. These projects were identified as transition-related and tracked closely with the expense amounts described above. Company witness Barrilleaux describes in further detail the TTC project approach and billing methods. I discuss the results of the TTC costs billed to EGSI-Texas later in my testimony.

Q. HOW ARE THE TTC COSTS ORGANIZED IN THE COMPANY'S FILING?

A. The costs are tracked by project codes that were identified as TTC-related work. These codes include the TTC expense group and the TTC-related capital codes described above; project codes related to specific portions of the Energy Efficiency program; and the project codes related to the 2004 rate case that the Company filed as a result of the Commission's June 2004 decision (and July order) to cease efforts to pursue ROA in ESAT prior to an implementation of a Federal Energy Regulatory Commission ("FERC")-approved RTO (or other Commission-approved independent entity).

These TTC project codes have been grouped within related work functions into "classes" for testimony discussion purposes. Each witness sponsors classes (related areas of TTC work) comprised of these individual project codes.

Q. WHAT WAS DONE TO EDUCATE EMPLOYEES ABOUT THE NEW PROJECT CODES AND THE TIMEKEEPING RELATED TO TTC COSTS?

A. The Controller–Utility Operations prepared a memorandum entitled "Entergy System-wide Guidelines for Identifying and Tracking Transition Costs" ("Tracking Guidelines"), which is attached as Exhibit PRM-5. Transition Management posted this memorandum on the Entergy Intranet so that all employees had access to the memorandum. Employees of Transition Management also met with key functional areas to review the guidelines. The following is a summary of the key points contained in the Guidelines:

- definition of TTC costs
- criteria for determining whether TTC costs are recoverable;
- instructions for the selection of project codes;
- instructions for the approval of TTC capital projects;
- preference for directly assigning TTC costs to the jurisdiction for which the costs were specifically incurred, whenever possible;

- instruction to have non-affiliate TTC costs tracked with the same project codes; and
- contact information for subject matter experts who can answer questions regarding the accounting for TTC costs.

Q. WHAT WERE THE CRITERIA FOR DETERMINING WHETHER TTC COSTS ARE RECOVERABLE?

A. The Tracking Guidelines presented the criteria for determining whether TTC costs were recoverable in the form of the questionnaire in Exhibit PRM-5. Employees had to consider seven questions:

1) Is the cost incurred required to carry out Texas' transition or to implementation of ROA mandated by statute or regulation?

2) Is the cost incurred directly associated with ROA, *i.e.*, the activity or initiative incurring the cost solely undertaken to implement ROA?

3) Is the level of expenditure prudent and reasonable?

4) Is the cost expected to be recoverable in a competitive retail market?

5) Is the cost associated with competing to provide a product or service that is authorized for competition?

6) Is the cost associated with marketing or promotional activities?

7) Is the cost for professional or advisory services or legal services specifically associated with the development of competitive strategies?

Only if the employee could answer the questions 1 through 3 "YES" and questions 4 through 7 "NO" was a cost recorded to a recoverable project code reflected in the Tracking Guidelines. Specific tables of these project codes were set up for charges that were either 100% for the Texas portion of EGSI (Table 2 of Exhibit PRM-5), 100% EAI (Table 1 of Exhibit PRM-5), or allocated to multiple jurisdictions (Table 3 of Exhibit PRM-5). These tables are explained in more detail in my Exhibit PRM-5.

Q. WERE THE TRACKING GUIDELINES REVISED OVER TIME?

A. Yes. The Guidelines were updated to reflect evolving developments in market mechanics requirements and regulatory processes. As employees began working on the implementation of FERC Order No. 2000 related to the formation of Regional Transmission Organizations ("RTOs"), accounting personnel revised the Guidelines to include a warning that costs related to the implementation of FERC Order No. 2000 should not be billed to the TTC project codes. Also, when Arkansas repealed Act 1556 authorizing the implementation of ROA in that state, accounting personnel revised the Tracking Guidelines to advise employees that the TTC project codes for TTC costs attributable to Arkansas were closed.

Q. WERE THERE ANY OTHER EFFORTS TO EDUCATE EMPLOYEES REGARDING THE USE OF THE TTC PROJECT CODES?

A. Yes. Transition Management made an employee available to respond to questions from the various business units regarding the appropriate use of TTC project codes. This person was knowledgeable about the project codes and the Tracking Guidelines. Thus, this service acted to assure that the projects codes were accurately utilized by the business units.

Q. DID THE FINANCIAL PROCESSES THAT WERE USED TO PLAN, MONITOR, AND CONTROL TTC COSTS SUPPORT PRUDENT MANAGEMENT OF TTC COSTS?

A. Yes. The financial processes supported the prudent management of TTC costs. The financial processes enabled the business units, the jurisdictional presidents, and Transition Management to manage costs based on timely information on what factors were driving TTC costs. Also, the financial processes aligned incentives for cost management with accountability for results.

2. TTC Cost Trends

Q. PLEASE SUMMARIZE THE TIMELINE OF EGSI'S TRANSITION TO COMPETITION AND RELATE THE TTC COSTS TO THE TIMELINE.

A. The timeline and amounts of all requested TTC costs (both capital and non-capital plus attendant AFUDC) incurred in each of the years of the period over which the TTC costs were incurred (that is, the "TTC cost period") are as follows: