reasonable expenditures imposed by SB 7 or Commission directive. The time value of money is well established at the Commission. Without recognition through carrying costs that the expenses were spread over six years, the Company would not be made whole. As requested, the carrying cost rates should be those recognized by the Commission to estimate what capital costs the Company.

Q. WHAT DO YOU SEE FOR THE LONGER TERM?

A. Recovery of these transition costs closes out the first phase of the transition to competition for EGSI. In the longer term, it is clear EGSI still intends to move toward retail open access in Texas and it is clear both the Legislature and regulators support that intention.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

DOCKET NO. ____________

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

DIRECT TESTIMONY

OF

VIKKI G. CUDDY

ON BEHALF OF

ENTERGY GULF STATES, INC.

AUGUST 2005

## SUMMARY OF DIRECT TESTIMONY OF VIKKI G. CUDDY

Vikki Cuddy is a Principal with Structure Consulting Group, LLC. She oversees and monitors the development of projects in Structure Consulting Group's North American energy consulting practice.

Ms. Cuddy's testimony compares Entergy Gulf States, Inc.'s transition costs with the transition costs incurred by electric utilities and other market participants around the country involved in the creation of systems, processes and markets to support retail competition. Ms. Cuddy also develops an estimation model, based on a series of inputs from industry standards, statistical benchmarks, personal experience, and other sources, and uses that model to compare Entergy Gulf States' transition cost to the costs that could reasonably be expected to be incurred in acquiring the infrastructure and services necessary to Entergy Gulf States' transition to competition. Ms. Cuddy demonstrates that Entergy Gulf States incurred a reasonable level of transition costs when one considers the length of Entergy Gulf States' transition period (June 1, 1999 through June 17, 2005), the Commission's directives to Entergy Gulf States, and the evolving regulatory and infrastructure requirements applicable to retail open access in the Entergy Settlement Area in Texas.

DOCKET NO. ________

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

DIRECT TESTIMONY OF VIKKI G. CUDDY

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## EXHIBITS

## I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Vikki Gates Cuddy. I am employed by Structure Consulting Group, LLC ("Structure") as a Principal. My business address is 2000 West Sam Houston Parkway South, Suite 1600, Houston, Texas 77042.

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 JOB RESPONSIBILITIES?

A. As a Principal with Structure, I am responsible for monitoring the development and implementation of competitive wholesale and retail electric markets across the Midwest, Southeast and Texas, as well as for the oversight of Structure personnel working on projects in these regions. In my role as Principal, I have focused on facilitating the development of market rules and subsequently translating those market rules into viable system design specifications.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I have a Bachelor of Science in Business Administration from the University of the Pacific. From 1996 to 1999, I was employed by Ernst & Young (now CapGemini Ernst & Young) in the San Francisco office in its management consulting practice. I was responsible for assisting clients in the design and development of processes and systems to support competitive energy markets in California and Ontario. Specifically, on behalf of Pacific Gas & Electric Company, I designed, built and tested interfaces to validate and load data from the California Power Exchange into a custom-built settlement system. Additionally, I assisted Hydro One, which is a holding company that emerged from the restructuring of Ontario Hydro as the owner and operator of the wires operations formerly provided by the provincially owned utility, in preparing for wholesale and retail deregulation.

In 1999, I joined Structure. During my employment with Structure, I have had an array of experiences and responsibilities. In 2000, I was assigned to a project at the Electric Reliability Council of Texas ("ERCOT") in which I assisted in the development of the market structure, organizational infrastructure and business processes for ERCOT in preparation for retail open access in Texas. In 2001, I was retained by ERCOT as a Market Trials Coordinator, where I was responsible for the daily communication to market participants of ERCOT's commercial and operational system readiness to support the ERCOT wholesale market. In 2002, through a portion of 2003, I was retained by the Company to assist with the development of protocols for wholesale and retail operations reflecting procedures available to a Competitive Retailer for Day 1 Operations in what is known as the Entergy Settlement Area of Texas ("ESAT"). These protocols were essentially market rules which were intended to provide a foundation for retail competition in EGSI's Texas service area. In 2003, Structure was retained by the Midwest Independent System Operator ("MISO") to conduct an assessment of market readiness. MISO is a Federal Energy Regulatory Commission ("FERC")-approved Retail Transmission Organization acting in close cooperation with 15 states and the province of Manitoba. Structure's readiness assessment for MISO involved evaluating implementation procedures, participant qualification, participant registration, technical readiness and training for MISO. In the latter part of 2003, I accepted the Independent Coordinator role in connection with the Texas nodal market development for ERCOT, which involved coordinating a collaborative stakeholder process to develop protocols supporting a nodal market and overseeing the completion of a detailed cost-benefit analysis. As the Independent Coordinator, I facilitated meetings on nodal market design with the ERCOT stakeholders, reported on the status of market design to the Commission, and coordinated stakeholder education activities and meetings. Most recently, Structure has completed a cost assessment for the Northern Ireland Authority of Energy Regulators and the Commission for Energy Regulation in the Republic of Ireland. This assessment included estimating the implementation costs of creating an entity to operate a single-energy market across the island of Ireland, which included a detailed inventory of systems, personnel and market functionality. Structure has also been retained to identify the key cost drivers and components associated with the start-up and on-going maintenance of a Regional Transmission Organization ("RTO") for GridWest, and to provide a context for GridWest of the various RTO cost components to enable GridWest to understand how they may be similar or different.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCIES, INCLUDING THE PUBLIC UTILITY COMMISSION OF TEXAS?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony assesses the reasonableness of certain portions of the costs submitted in 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. My focus is primarily on the overall implementation of the transition requirements as they relate to two of the four categories of TTC cost classes displayed in the "Foundation Chart" included in my testimony as Exhibit VGC-1. This Foundation Chart is also included in the testimony of other EGSI witnesses, including Company witness Phillip R. May. The Foundation Chart provides a graphic depiction of the various classes of costs that make up EGSI's TTC request. The Foundation Chart identifies the individual classes of cost, by witness, and amount. There are four major categories of cost classes shown on the Foundation Chart, including the two categories of cost classes upon which I focus on in this testimony: the "Plan, Develop Rules & Business Support" and "Design, Build, Test, Pilot & Maintain Systems" cost categories.

Q. WHY ARE YOU QUALIFIED TO PROVIDE THIS TESTIMONY?

A. I am thoroughly familiar with the Company's transition efforts. I worked with the Company and all active stakeholders over a two-year period in developing the ESAT Protocols as part of the transition. The Public Utility Commission of Texas (the "PUCT" or the "Commission") and the FERC approved the ESAT Protocols in 2003 and 2004, respectively. My role with the ESAT Protocols included a detailed analysis of the retail functions performed by ERCOT, and guidance to the stakeholders (including EGSI) regarding the functions to be performed by the Company in order to support retail choice in the ESAT region. This experience, combined with my knowledge of the retail and wholesale functions required under Senate Bill 7 ("SB 7"), obtained through my engagements with both ERCOT and the Company, provides me a thorough understanding of the processes and systems necessary to implement retail choice in Texas.

Additionally, for the past eight years, I have participated in large scale system implementation and process improvement initiatives with my clients to support wholesale and retail competition in North America and Europe. My projects have included active roles in cost estimation, project management, delivery, execution, vendor negotiation, and selection. These projects have provided the experience necessary to estimate and evaluate large-scale systems design and implementation projects.

Q. DO YOU SPONSOR ANY EXHIBITS IN THIS FILING?

A. Yes, I sponsor the Exhibits listed in the Table of Contents to this testimony.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section II, I provide an overview of EGSI's unique experience in its efforts to move to ROA. In Section III, I provide an estimate of what a utility in EGSI's situation should have expected to spend on the transition to competition under SB 7 over a transition period that exceeded five years. In Section IV, I examine comparisons of EGSI's transition and its associated costs to the transition activities and transition costs incurred by other utilities and participants in transition to competition activities, such as

ERCOT. In Section V, I address the reasonableness of EGSI's TTC costs. I conclude my testimony in Section VI.

## II. OVERVIEW OF EGSI'S TRANSITION TO COMPETITION

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this Section II, I first briefly discuss the efforts that EGSI has undertaken since the passage of SB 7 in 1999 to make the transition to retail choice. Second, I describe the uniqueness of EGSI's experience. Third, I describe efforts outside of ESAT to transition to retail choice. Fourth, I provide evidence of the costs incurred by other entities for similar efforts in comparison to EGSI's transition costs.

Q. PLEASE DESCRIBE EGSI'S EFFORTS TO TRANSITION TO RETAIL CHOICE.

A. Because I have worked with EGSI closely over the past few years, I am generally familiar with what the Company has undertaken with regard to ROA transition. These activities include participation in many Commission projects, dockets and hearings, as well as internal transition planning and system development. To summarize, first, the EGSI transition occurred primarily over a five-year period from June 1999 to June 2004, although the actual transition period extended to June 17, 2005. During that period, as other Company witnesses explain, EGSI expended substantial efforts with both internal and external resources to plan and implement its operations and systems in anticipation of ROA. In addition to this work in Texas, the Company participated in related proceedings in Louisiana and at the FERC. EGSI also participated in numerous contested case and rulemaking dockets at the PUCT, including the Customer Choice Pilot Project, and development of the ESAT Protocols. EGSI also participated actively in the collaborative sessions convened to address and resolve market structure and transparency issues in ERCOT.

Q. IS THERE ANYTHING UNIQUE ABOUT EGSI'S EXPERIENCE WITH ITS TRANSITION?

A. Yes. EGSI has had the longest active transition period of any utility in Texas. By the summer of 2001, all investor-owned electric utilities in Texas were on track to implement retail choice in their service territories on January 1, 2002 except for El Paso Electric Company and Southwestern Public Service Company ("SPS"), both of which were subject to legislation by that time that exempted them from moving to ROA until sometime after January 1, 2002. In the fall of 2001, however, the Commission issued two orders that delayed the start of ROA for EGSI and Southwestern Electric Power Company ("SWEPCO") beyond January 1, 2002.

Q. DID THE COMMISSION TAKE THE SAME APPROACH TO PURSUING ROA IN EGSI'S AND SWEPCO'S SERVICE AREAS AFTER THE DELAYS?

A. No. EGSI proceeded under a Commission-approved settlement in Docket No. 24469 to pursue ROA through a number of regulatory proceedings that ultimately were referred to as "milestones." These milestones included a market protocols project, which ultimately became a contested case docket before both the Commission (Docket No. 25089) and the FERC; an "Interim Solution" docket (Docket No. 27273); and an "Independent Organization" docket (Docket No. 28818). From December 2001 until the spring of 2004, the Commission indicated that it intended for EGSI's service territory to move to ROA as soon as possible, and set target dates for achieving that goal.

Somewhat like EGSI, SWEPCO, after its delay, was first subject to a docket (Docket No. 24468) that was initiated to determine whether that company's service territory was ready for ROA. In that proceeding, however, the SWEPCO parties entered into a settlement, ultimately approved by the Commission in Docket No. 24869, that took a different approach from EGSI's settlement in Docket No. 24469. The SWEPCO settlement did not assume that ROA would commence in the near-term. The Commission's May 2003 order approving the SWEPCO settlement did maintain SWEPCO's customer choice pilot project and already-existing low-income projects, but it explicitly, indefinitely delayed ROA in SWEPCO's region until: (1) "at least January 1, 2007"; (2) certification of a power region; and (3) competitive REPs are providing service to all major customer classes in the pilot project. The Commission also authorized SWEPCO itself to perform customer registration functions and to convey switch information to market participants.

SWEPCO, unlike EGSI, did not: initiate and participate in protocols dockets at the Commission or the FERC; use ERCOT as its registration agent, operate under an "interim solution" requirement or expectation; initiate and participate in an Independent Organization docket; or continue to stand ready to enter ROA in the near-term under target dates established in Commission orders.

Q. HOW MANY MONTHS DID EGSI SPEND IN ITS TRANSITION PERIOD FROM THE TIME SB 7 WAS PASSED TO THE TIME THE COMMISSION DECIDED TO INDEFINITELY DELAY ROA FOR EGSI?

A. The bulk of the effort occurred over an approximately 60 month time period: from the middle of 1999 with the passage of SB 7 through June 2004, when the Commission ruled that it would no longer pursue an interim solution for EGSI. The actual transition period, however, extended over 72 months from June 1, 1999 through June 17, 2005, when new legislation addressing EGSI's ROA efforts became effective. This is compared to the roughly 30 months that the ERCOT utilities spent preparing for retail choice (from the middle of 1999 to January 1, 2002).

Q. MORE SPECIFICALLY, WHAT TRANSITION-RELATED ACTIVITIES DID EGSI UNDERTAKE DURING ITS EXTENDED DELAY PERIOD THAT WERE BEYOND THE TRANSITION ACTIVITIES CONDUCTED BY ERCOT UTILITIES?

A. The major dockets or projects, as indicated above, were the "Readiness" docket itself (Docket No. 24469); the Protocols projects and dockets (including three hearings before the Commission); the "Interim Solution" docket and hearing; and the "Independent Organization" docket and hearing. EGSI also maintained its pilot project during this period, and maintained its certification with the ERCOT registration agent. These activities, including significant work internally and with outside contractors to plan and implement systems for ROA, are described in more detail by the Company witnesses, including Company witnesses Joseph F. Domino and May.

## III. <u>ESTIMATION APPROACH AND FINDINGS</u>

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section, I compare the reasonableness of EGSI's requested TTC costs to an estimate of what it would cost for an entity to implement ROA in a geographic market under the rules and expectations that applied to EGSI.

Q. HOW HAVE YOU COMPARED THE REASONABLENESS OF THE TRANSITION TO COMPETITION COSTS REQUESTED BY THE COMPANY?

A. I have created an estimation model to use as a comparative tool attached as Exhibit VGC-2, Cost Estimation Model. The spreadsheet is based on a series of inputs from industry standards, statistical benchmarks, professional experience, and other sources that are contemporaneous to the time frame in which EGSI incurred its TTC costs. This estimate assumes a 60-month intense and active transition period that focused on near-term ROA, as was the case for ESAT. Using the timeline and changing requirements as the baseline, I derived a reasonably expected cost of implementing retail choice in the Company's Texas service territory. Essentially, the spreadsheet estimates the cost of accomplishing the transition activities captured in the "Plan, Develop Rules & Business Support" and the "Design, Build, Test, Pilot & Maintain Systems" categories of the Foundation Chart attached to my testimony as Exhibit VGC-1. For the Company, these costs are comprised of most of the classes sponsored by Company witnesses May, Thomas R. Manasco, Andrew E. Quick, and William T. Craddock. They do not include Mr. May's System Benefit Fund/Renewable Energy Credits class, or his

Rates/Riders Preparation class, and does not include the Energy Efficiency class of costs sponsored by Company witness Karen M. Radosevich. The estimation model also does not include any Allowance for Funds Used During Construction ("AFUDC") accruals on capital items or any other amounts for carrying cost. I understand that the Company's figures presented in the Foundation Chart do include AFUDC for their capital items. Therefore, if I were to include an AFUDC component in my figures, my figures would be even larger in comparison to EGSI's TTC costs reflected in the Foundation Chart. I then compare my estimate to the actual costs incurred by EGSI in carrying out those activities.

1. Overall Estimation Approach

Q. WHAT IS YOUR OVERALL APPROACH TO ESTIMATING THE TRANSITION COSTS?

A. At the highest level, I approached this estimate as if I were preparing to bid on a large-scale project implementation, such as bidding on a Request for Proposal published by a utility that needs all of the functionality to prepare for and participate in a retail pilot project and then for full ROA. I used market rates from 1999-2000 for internal resources and outside services and, where available, industry averages for system license and maintenance costs. The model uses a "drill-down" approach. The costs are summarized as total transition costs, which include cost estimate summaries for external resources, internal resources, system costs, and contingencies.

When available, benchmarks were referenced and noted in the spreadsheet. The "bid" has several different components, each of which corresponds to the section of the Foundation Chart that forms the point of comparison. As my testimony continues, I explain the methodology and rationale behind the systems, personnel, and infrastructure estimate. Where relevant, I highlight where project costs were influenced by outside forces. Finally, I have inserted columns to capture the variance between costs reported by the Company and the estimate of that particular category based on the cost information provided to me.

Q. HOW IS THIS MODEL DIFFERENT FROM A TRADITIONAL PROPOSAL TO BID?

A. There are two fundamental elements of this spreadsheet that are not normally included in a bid proposal that I would typically prepare as a vendor. First, in addition to the system and implementation cost estimate, the spreadsheet also includes allocations for internal resources and infrastructure such as facilities, network connectivity, benefits loading, and telecommunications costs to provide a total cost comparison. Bid proposals typically do not include an estimate of internal costs that would be incurred by a company to implement the work proposed by the vendor.

Second, the estimate benefits from the knowledge of historical facts and outcomes that would not be reasonably known by the vendor at the time of the original contract negotiations. It utilizes known information regarding changes in the project duration, market scope, market maintenance requirements, manual workarounds, and changing regulatory requirements.

Q. WHAT TIMELINE DID YOU INCLUDE IN YOUR ESTIMATION MODEL?

A. My estimate begins to account for work effort and costs on and after June 1, 1999. I match the implementation timeline through January 1, 2002 consistent with the implementation timeline that ERCOT used for its retail market implementation. This timeline is included as Exhibit VGC-3, ERCOT System Overview. Beyond January 2002, I use the unique timeline and requirements defined for the Company through the "Readiness" docket itself (Docket No. 24469); the Protocols projects and dockets (including three hearings before the Commission); the "Interim Solution" docket; and the "Independent Organization" docket and hearing. The estimate covers the Company's activities from June 1, 1999 until September 1, 2004. I include time through September 1, 2004 to capture limited, but necessary, wind-down of resources and systems after termination of the pilot project in June 2004.

Q. HOW DID YOU DETERMINE THE NUMBER OF RESOURCES TO ALLOCATE TO THIS PROJECT?

A. My approach to resource allocation was different for internal versus external resources. To determine the internal resources, I relied on two major sources. First, I referred to the roles and functional scope described by ERCOT for its Commercial Operations department, as captured in a presentation to the Gulf Coast Power Association by Bill Bojorquez on the "New Rules of the Texas Power Game" in June 2000, and included in my testimony as Exhibit VGC-4, New Rules of the Texas Power Game. The functions of the Commercial Operations department, which include registration, meter data acquisition, data aggregation, settlement, invoicing, market rules compliance and administration, as well as information technology and application support, closely align with the requirements the Company needed to perform to prepare for and to support pilot operations. The functions of this department, previously referred to as the "Settlement and Client Services" department by ERCOT, are relevant to defining the roles of internal resources. Additionally, I relied on personal experience of working with Regional Transmission Organizations ("RTOs"), including the Midwest ISO and PJM, and various market participants to derive the roles that internal resources would perform over the project. As a quick comparison, I estimated up to 114 different roles working on the project internally, with a peak of 90 internal resources allocated to the project.

For external resources, I approached the estimate as if I were "bidding" as the prime system integrator. I evaluated the skill sets necessary to build, test and maintain the systems, and the processes required for ROA in Texas. For each major functional module, I assigned a functional lead and, in most cases, a technical lead. Depending on the complexity of the module, I assigned a varying number of developers and testers. To ensure there was overall continuity and integration of the design, I assigned solution architects who would be responsible for identifying integration risks, completing integration testing, and overseeing performance testing. Once the roles were established based on the functional modules, I assigned overall team leads or project managers based on the ratio of analysts, designers, and developers that were working on the functional modules. These leads would be responsible for preparing and presenting routine status reports, managing project timelines, mitigating project risks, and providing overall leadership to the development and implementation teams. I have six leads assigned to the project, which had a peak of 78 external resources working on the project and a net of 134 different roles over the course of the project.

### 2. Functional Scope

Q. WHEN YOU REFER TO FUNCTIONAL MODULES, WHAT ARE YOU INCLUDING IN THE FUNCTIONAL SCOPE?

A. The functions that are included in my estimate are driven from requirements of the above-described regulatory dockets, the ERCOT Protocols, the ESAT Protocols, and the requirements of SB 7. With the exception of the General functional module, each functional module includes estimates to define the requirements, design, build, and test the necessary systems, and operate and maintain (including upgrade) these modules once the pilot was operational. The functional modules include the following:

Information Technology Acquisition and Integration: The Company was required to implement significant system additions and upgrades to be in compliance with Texas ROA requirements. The estimation model includes acquisition of, or upgrade to, the Company's existing information technology infrastructure. The estimation model also includes the necessary monitoring and contingency equipment to sustain business operations in the event of a primary application or interface failure of critical applications. Furthermore, the model estimates the cost of maintaining each of these applications after initiation of the pilot.

Customer Information System: The identification and implementation of system modifications for the Distribution Company and acquisition and configuration of a customer information system ("CIS") for the affiliated retail company.

Registration and Texas Standard Electronic Transactions: monitoring and complying with the system and process requirements defined through the ERCOT Texas Standard Electronic Transactions ("Texas SET") working group and the ERCOT Protocols. This module also includes the development of electronic data interchange ("EDI") capabilities and integration of those capabilities with the CIS for both the distribution and retail operations.

Data Aggregation: This module includes identifying and implementing systems and processes to process load consumption data, and to interface with REPs using Texas SET.

Load Profiling: This module includes monitoring and complying with load profiling standards developed through ERCOT stakeholder processes, including assigning load profile types, installing mandatory interval data recorder meters, and posting load profile models.

Load Forecasting and Counter-Party Trading: This module includes identifying and implementing specific requirements of the affiliate REP to conduct business under ROA, in addition to the Texas SET requirements addressed above.

Market Information Postings: This module includes developing and implementing an electronic information system – known as "CRIS" – to distribute market-related information to REPs and the general public.

General: Finally, there are functional requirements that are not tied to specific system functions. This General functional module includes the effort necessary to plan transition efforts, manage compliance, participate in regulatory proceedings, and manage overall project delivery success.

The estimation model includes required changes to several practices and operations of the Company to separate competitive activities from transmission and distribution utility activities, and to implement a code of conduct. This includes the creation of an affiliate REP and the costs that were required to implement business and corporate separation activities to comply with the code of conduct. The model includes an estimate on the various expenses including use of strategic advisory services, wholesale market interaction services, and fees for legal services associated with compliance.

Q. DOES YOUR ESTIMATE INCLUDE ANY CONTINGENCIES?

A. Yes. After completing the detailed estimate, I increased the total amount by 10% to account for contingency. In my experience, this percentage is lower than average for a bid. In fact, if a client were requesting a fixed-price bid over a timeline of this length (five years), it is not uncommon to use a contingency of over 50%. If a client requested a time and materials bid, I would likely have placed a 20-25% contingency on outside services. I am comfortable, however, with the 10% contingency because some typical project risks and unknowns, like slipped timelines and changing market requirements, are already factored into the estimate. For example, I allocated a "Fix-It" team under outside services to process manual workarounds and keep the Company compliant with Texas SET while the market awaited critical design changes slated for version 1.5 of Texas SET.

3. Total Cost Estimate and Model Assumptions

Q. WHAT TOTAL AMOUNT DOES YOUR SPREADSHEET INDICATE IS A REASONABLE ESTIMATE FOR EGSI'S TRANSITION ACTIVITIES RELATED TO THE "PLAN, DEVELOP, RULES & BUSINESS SUPPORT" AND THE "DESIGN, BUILD, TEST, PILOT & MAINTAIN SYSTEMS" CATEGORIES OF THE FOUNDATION CHART?

A. The following table, as extracted from Exhibit VGC-2, Cost Estimation Model summarizes my estimate of total transition costs, compared to the two categories of costs from the Foundation Chart upon which I focus, at approximately $169 million. This amount includes cost estimates for outside services, system acquisition and maintenance agreements, and internally dedicated project personnel that would be necessary to design, build, test and maintain the retail pilot. In contrast, the Company is seeking approximately $144 million for these same transition components. As I explained previously, my estimate does not account for all of the TTC costs requested by EGSI, including: the System Benefit Fund/Renewable Energy Credits class costs; the Energy Efficiency class costs; the Rates/Riders Preparation class costs; AFUDC, and carrying costs.

Table 1 – Total Transition Cost Estimate

## EGSI Comparative Cost Estimate

### Schedule 1: Summary of Total Transition Costs

| Line | Description | Subtotal | Transition Estimate |
|---|---|---|---|
| 1 | | | |
| 2 | Internal Resource Costs | $ 35,065,854 | |
| 3 | *Labor & Benefits* | | 24,859,375 |
| 4 | *Training, Travel & Other Employee Expenses* | | 1,599,000 |
| 5 | *Utilities, Maintenance & Building Facilities* | | 5,200,542 |
| 6 | *Other* | | 3,406,938 |
| 7 | | | |
| 8 | External Resource Costs | $ 67,456,500 | |
| 9 | *Consulting for Implementation* | | 67,456,500 |
| 10 | | | |
| 11 | | | |
| 12 | *Systems Costs* | | |
| 13 | *Acquistion* | $ 21,777,331 | |
| 14 | *Customer Care System (CCS)* | | 9,664,200 |
| 15 | *Competitive Retailer Information System* | | 214,500 |
| 16 | *Load Profiling and Data Aggregation* | | 2,210,700 |
| 17 | *Data Exchange* | | 5,776,710 |
| 18 | *Load Forecasting* | | 330,100 |
| 19 | *Counterparty Trading System* | | 1,040,000 |
| 20 | *Other* | | 2,541,121 |
| 21 | *Maintainence* | $ 29,573,737 | |
| 22 | *Customer Care System (CCS)* | | 6,442,800 |
| 23 | *Competitive Retailer Information System* | | 338,000 |
| 24 | *Load Profiling and Data Aggregation* | | 6,442,800 |
| 25 | *Data Exchange* | | 12,436,840 |
| 26 | *Load Forecasting* | | 920,400 |
| 27 | *Counterparty Trading System* | | 960,000 |
| 28 | *Other* | | 2,032,897 |
| 29 | | | |
| 30 | Contingency | $ 15,387,342 | 15,387,342.18 |
| 31 | | | |
| 32 | **Total Transition Costs** | | **$ 169,260,764** |

Q. IS IT APPROPRIATE TO COMPARE CERTAIN LINE ITEMS OF COST IN YOUR ESTIMATION MODEL WITH SPECIFIC TYPES OF COSTS INCLUDED WITHIN THE COMPANY'S TTC COST RECOVERY REQUEST?

A. No. My model is an independent assessment of what it would cost to transition to ROA in ESAT based on the cost development method I used for the model. As such, it is appropriate to compare the total costs derived from the model to the total costs in the two categories of TTC cost classes from the Foundation Chart. My model is not intended to be a line-by-line comparison to the costs that EGSI incurred.

Q. DESCRIBE THE ASSUMPTIONS THAT YOU USED IN THE MODEL.

A. The model uses a series of assumptions related to personnel, infrastructure, systems, and general project implementation costs through a set of worksheets comprising model "Inputs," "Workpapers," and "Schedules." The assumptions, rates, and system development lifecycle are derived from my professional experience and industry benchmarks for project implementations of a similar nature. With respect to the time frame, the model uses the known timescale for the project implementation.

Q. WHAT ARE THE ESTIMATION INPUTS THAT YOU USED IN THE MODEL?

A. The inputs used in the model are broken down by estimating factors, external resource rates, personnel salary grades, and resource loading. In the "Input 1 – Estimating Factors" worksheet the assumptions are displayed by "Category," "Type," "Factor Name," "Description," "Estimate," and "Data Source / Basis for Estimate."

The four categories are: "Personnel," "Facilities," "Infrastructure," and "General." An example of a "Personnel" category cost is "$_supplies_per_fte," which assigns an estimated annual cost for supplies per each full-time employee based on an industry standard. An example of an "Infrastructure" category is the "$_per_hourly_meter," which is an average cost to install retail compliant metering based on a published guide of average hourly metering at commercial sites. An example of a "Facilities" category cost is "$_lease_ft," which assigns a cost per employee for use of office facilities. An example of a "General" category cost is the "$_non_ERCOT_LSE_Fee," which is uniquely pertinent to this cost estimate and is the annual fee per Electronic Service Identifier ID ("ESI ID") for non-ERCOT Load Serving Entities ("LSEs") based on the actual ERCOT charge.

In addition, each of the items listed as an estimating factor is one of two types: "Calculated" or "Direct." Calculated costs are those that have a dependency on other input data such as the "#_employees" factor, which is dependent upon the resource loading input chart, identified as "I2-Resource Cost." Direct costs are those that are specifically defined on the "Input 1 – Estimating Factors" worksheet. Modification of any of these estimate values, either the calculated values or the directly assigned values, impacts the cost estimate on the Schedule and Workpapers.

The second key input information is contained in the "Input 2: Resource Cost" worksheet. This worksheet captures the assumptions made for the salaries of permanent full-time employees as well as the cost of non-permanent full-time resources. The cost of the permanent FTEs is displayed in two columns: "Fully Loaded" and "Salary Cost 1999." The salary ranges in Salary Cost 1999 are based on 1999 salary estimates from public market data comparisons, such as Monster.com. The Fully Loaded Cost is driven by multiplying the Salary Cost 1999 against the "%_loading_rate" factor which is a direct cost depicting the benefit loading rate to be applied to each employee. With respect to the non-permanent FTEs, the value displayed in the Salary Cost column is derived by multiplying the "Hourly Rate" column by the "Hours/Month" column and by number of months in the year. A benefit loading rate is not applied to these resources. The "Hourly Rate" and the "Hours/Month" columns are populated with general consulting rates and typical resource loading for specified levels in a consulting firm consistent with proposals that I have submitted in the past, with professional experience reviewing and hiring contractors, and with rate information obtained through research of other utilities.

The third key input information is contained in the "Input 3: Internal Resource Loading Detail by Role." This input sheet is the key tool for determining the cost of internal resources throughout the project lifecycle. Each of the resource positions is broken down by "Category," "Division," "Department," "Role," "FTE Salary ID," "# of FTE," "# Months," "Base Year Salary," "Start Date," and "Stop Date." The categories tie the resource costs to specific activities denoted in the Foundation Chart and are defined as: Business Continuity; Pilot Operations; General; Market Mechanics; Market Rules; Regulatory Affairs; Transition Planning; and Project Management. The "Base Yearly Salary" value is derived from the input in the "FTE Salary ID" and then determined from the input in the "Input 2: Resource Salary/Cost worksheet." The remainder of the columns denote the resource loading from the period beginning Q1 1999 through Q2 2004. Based on the value input in the "# of FTE," a full-time equivalency number populates a quarterly employee headcount based on the resource's defined start and stop dates.

Q. HOW ARE THE INPUTS USED TO DERIVE THE COSTS REPRESENTED ON THE SUMMARY WORKSHEETS?

A. The inputs used in the model are factored into a series of five workpapers. Each workpaper uses the input factors and summarizes the information over the project lifecycle for each specific area. The workpapers include:

Workpaper 1: Internal Resource Loading - summarizes the costs of the resources into two main categories: "Labor and Benefits" and "Employee Expenses."

Workpaper 2: External Resource Loading - derives a total cost per resource and project for non-permanent FTEs.

Workpaper 3: Facilities Summary - derives the facilities cost over the period 1999-2004 based on the resource headcount in a specified quarter.

Workpaper 4: Systems Summary - derives the application license and maintenance costs of various systems necessary to support the retail requirements for ESAT.

Workpaper 5: Other Transition Expenses Summary - highlights the transition costs associated with various fees and activities associated with the transition effort.

Q. WHERE ARE THE TOTAL TRANSITION COSTS SUMMARIZED IN THE MODEL?

A. In "Schedule 1: Summary of Total Transition Costs," the costs are summarized as total transition costs, which includes cost estimate summaries for external resources, internal resources, system costs, and contingencies. In Schedule 1, the line item references the applicable "Workpapers" where the detailed calculation was derived. The key column is the "Transition" cost, or the cost estimated in the workbook as derived through the "Inputs" and "Workpapers." The "EGSI Cost" column and the "% Variance" column compare the reported EGSI costs and the variance of those costs from the estimate being provided in this workbook.

To reiterate, this estimate applies to the costs of planning and implementing a retail choice pilot project and being ready for full ROA over a 60-month period. It covers both the distribution and retail aspects of such a project and accounts for the fact that systems requirements (such as Texas SET) were being revised throughout that period.

Q. WHY IS THIS MODEL CREDIBLE?

A. The entire model is built around the objective of providing a flexible, yet thorough, cost estimate. The basis of this model is built using the similar cost components and presentation framework as presented in the ERCOT budget filed with the Commission under Docket No. 28832, and attached to my testimony as Exhibit VGC-5, ERCOT Fiscal Year 2004 Budget.

Q. WHAT DO YOU CONCLUDE BASED ON THE RESULTS OF THE MODEL?

A. I conclude that, with regard to the two categories of EGSI's TTC cost classes upon which I focus, that the Company's TTC costs requested for recovery by EGSI are significantly lower than the costs produced by the estimate. That is, the Company's costs are lower than the costs that could be expected to be incurred for a utility, such as EGSI, to implement ROA in ESAT under the rules and requirements established through SB 7 for the types of costs included in those two cost categories.

## IV. COMPARISON OF EGSI TTC COSTS TO THOSE OF OTHER ENTITIES INVOLVED IN THE TRANSITION TO RETAIL COMPETITION

Q. WHAT IS THE FOCUS OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the availability and significance of data regarding transition costs incurred by other utilities and other entities involved in the transition to competition as comparative benchmarks against which to measure the Company's TTC costs.

### 1. Limited Benchmarking

Q. HAVE OTHER ELECTRIC UTILITY COMPANIES SOUGHT COMPARABLE RECOVERY OF TRANSITION TO COMPETITION COSTS?

A. No. There are many utilities that have undergone a transition to retail or wholesale competition in North America, but I have not found much information to be directly comparable to the recovery that the Company is seeking for three primary reasons. First, in reviewing regulatory proceedings outside of Texas, I found that, in many cases, the primary component of the recovery requested was stranded asset costs. By stranded asset costs, I mean the costs to an electrical corporation for assets and obligations that may become uneconomic as a result of the establishment of a competitive generation market. Stranded asset costs may arise when market prices in a competitive market are too low to recover the utility's sunk costs in generation-related investments made under the expectation that the investment would be recovered fully through cost-of-service, regulated rates. Under traditional cost-of-service regulation, electric utilities: had agency-approved service territories; requested regulatory approval to build power plants and transmission lines; and were assured a reasonable opportunity to recover their costs from customers. In the new competitive environment, that assurance would no longer exist. As a result, most policymakers agree on the need for a period during which electric utilities would be allowed the opportunity to recover costs incurred, and investments made, that could be unrecoverable in a competitive market. These transition costs are often called "stranded costs" because they could be "stranded" as a result of the transition and move from regulation to competition. By way of contrast, EGSI's TTC costs are composed of costs actually expended in response to legislative and Commission directives in order to bring about the transition to retail competition.

Second, in the past under traditional cost-of-service electricity regulation, states permitted electric utilities to recoup their costs, plus a return on investment, in the rates they charged customers. Under deregulation, there are no such guarantees because the market sets prices. Specifically, under ROA in the ERCOT area of Texas, competitive Retail Electric Providers ("competitive REPs") have used participation in the restructured retail market and associated revenue as a mechanism to recoup their costs. But Retail Electric Providers affiliated with electric utilities ("affiliated REPs") have used the revenues gained from sales to retail customers at the "Price To Beat" set by the Commission to recoup their transition costs. Because participation in the restructured market (either through the sales at market-based rates or sales at the Price to Beat) do not require REPs to reveal their actual transition costs, no REP in Texas—competitive or affiliate—to my knowledge has made its transition costs public.

Third, no other company has expended as much effort or experienced the duration of transition as has the Company. Because the Company's situation is unique, there is only limited comparable data.

Q. ARE YOU AWARE OF ANY REGULATORY AGENCY THAT HAS STUDIED THE IMPACTS OF TRANSITIONING TO A COMPETITIVE ENVIRONMENT?

A. Yes. In October 2004, the Federal Energy Regulatory Commission Staff published a "Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" in Docket No. PL04-16-000. This report is attached as Exhibit VGC-6, FERC RTO Cost Study, to my testimony.

Q. HOW IS THE FERC STUDY RELEVANT TO THIS PROCEEDING?

A. The study estimates the cost of developing a "Day One" RTO that provides independent and non-discriminatory transmission service and satisfies the minimum requirements of FERC Order No. 2000. While the scope of the study focuses on wholesale electric restructuring, the study demonstrates that costs of RTO formation vary widely. For example, at the time the study was completed, Day One RTOs required an investment outlay of between \$38 million and \$117 million, and an annual revenue requirement of between \$35 million and \$78 million. The study also demonstrates that delay, or an extended transition period, also is a significant driver of increasing costs.

Q. WHAT FUNCTIONS ARE INCLUDED IN A DAY ONE RTO?

A. The Day One RTO functions, which vary significantly from the Company's retail choice requirements, include open access transmission service, scheduling authority and available transmission capacity determination, redispatch for congestion management, ancillary services, planning, parallel path flow mitigation, interregional coordination, and market monitoring. The Study assumes that a Day One RTO does not have bid-based, security-constrained economic dispatch, unit commitment, locational prices, financial transmission rights, or capacity markets as the Northeast and California ISOs have. These latter functions are considered "Day Two" functions and involve further costs, which were beyond the scope of the FERC study.

Q. HOW IS THE FERC STUDY APPLICABLE TO EGSI'S TTC COSTS?

A. The FERC Staff specifically captured insights on the impact of delay in the pursuit of transition efforts from four study participants who are RTOs—specifically the Midwest ISO, Southwestern Power Pool ("SPP"), ERCOT, and the PJM Interconnection. The study noted in its Executive Summary on page ii that:

> Primarily, respondents noted that delay is expensive. Cost overruns, particularly in software design, result from changing plans mid-course. Prolonged delay also increases the amount of interest paid on debt before operations commence and the RTO has a revenue stream. Conversely, full Day Two operations implementation at the organization's inception on an aggressive timeline is costly both in the amount spent hiring outside consultants and in the number of software re-works required after operations commence. The entities that developed in stages, moving from Day One to Day Two while adding functionality to meet their members' needs, reported less cost overrun and fewer required reconfigurations....

This insight is particularly relevant to EGSI's situation in at least two respects. First, like all market participants in Texas, the Company was subject to changing plans not only mid-course, but several different times, during the period in which it attempted to implement retail choice. Second, EGSI was also given an aggressive timeline at the onset to prepare for a retail pilot and, unlike any other investor-owned utility ("IOU") in Texas, was required to keep that pilot operating in full compliance with evolving market rules, even after retail choice was delayed initially beyond January 1, 2002.

Q. WHAT UTILITIES DID YOU RESEARCH IN YOUR EFFORT TO FIND COMPARABLE UTILITY BENCHMARK DATA?

A. Primarily, I researched the ratesetting of San Diego Gas & Electric ("SDGE") under Resolution ALJ 176-3049 dated November 17, 2000 at the California Public Utilities Commission ("CPUC"), and the application of The Detroit Edison Company ("Detroit Edison") to, among other things, increase rates, and amend its rate schedules governing the distribution and supply of electric energy filed in Case U-13808 at the Michigan Public Service Commission ("MPSC").

Q. WHY DID YOU FOCUS ON THESE UTILITIES?

A. I focused on these utilities because they are both IOUs in states that transitioned to wholesale electric choice and, in whole or in part, to retail choice.

Q. DID YOU FIND THAT THESE UTILITIES HAD COMPARABLE RECOVERY REQUESTS?

A. No.

Q. WHAT DID YOU CONCLUDE?

A. SDGE provided testimony supporting its proposed annual Competition Transition Charge ("CTC") revenue requirement of $115,000,000 for 2002. SDGE provided data, in its testimony, supporting the CTC revenue requirement that demonstrated that the amount for the CTC revenue requirement reflects the 12-month forecast of SDGE's market costs for the calendar year including the above-market costs for the administration of power purchase contracts with Qualifying Facilities and Portland General Electric, and the below-market costs for San Onofre Nuclear Generation Station Incremental Cost Incentive Pricing. The revenue requirement also set forth the 12-month amortization of the projected balance in the Transition Cost Balancing Account. Pursuant to SDGE's calculations and the order of the CPUC, SDGE's CTC revenue requirement of $115 million was granted.

Detroit Edison proposed to collect its stranded costs, which it directly attributed to lost sales volumes. According to Detroit Edison, stranded costs simply represent that part of the utility's approved revenue requirement that would no longer be recovered when its customers switched to other suppliers. Detroit Edison requested the MPSC to authorize the use of an electric choice mitigation adjustment to adjust costs associated with customers leaving under electric choice. Detroit Edison maintains that future stranded costs should be recovered through a transition charge that does not burden bundled customers.

In each of these cases, the recovery sought was for stranded costs, and are not comparable to the actual costs incurred by the Company to prepare and implement retail choice activities. I have addressed these cases, however, to demonstrate that what the Company is seeking—recovery of transition costs—is fairly unique.

Q. DID YOU REVIEW ANY COST RECOVERY REQUESTS OF TEXAS UTILITY COMPANIES?

A. Yes. I reviewed the proceeding granting recovery to SPS's retail transition efforts in Commission Docket No. 25088.

2. <u>Southwestern Public Service Company</u>

Q. DOES SPS'S COST RECOVERY COMPARE TO THE COMPANY'S REQUEST?

A. No. SPS, from the outset, was not subject to the ROA requirements that applied to EGSI. When SB 7 passed in 1999, SPS became subject to a unique set of provisions that addressed its situation as what the Legislature described as a "competitive development area." Unlike EGSI (or any other IOU in Texas), SPS was required to file its own transition to competition plan by December 1, 2000 (*e.g.*, original PURA §§ 39.401 and 39.402). In 2001, the Legislature amended those SPS-specific provisions through House Bill 1692, Act of May 26, 2001, 77th Leg., R.S., H.B. 1692 ("HB 1692"), to establish that ROA would *not* commence in SPS's Texas service territory until the later of January 1, 2007, or the date on which the Commission authorizes SPS to implement customer choice. Simply stated, SPS was on a different track to ROA than was EGSI, and the costs that SPS sought to recover did not include the ongoing personnel and the applications necessary to support a pilot, continuously maintain and certify compliance with ERCOT's registration agent, and the labor and expenses necessary to participate in multiple contested cases and other regulatory proceedings.

Q. WHAT DID SPS DO PRIOR TO ITS 2001 DELAY LEGISLATION (HB 1692) THAT STOPPED ITS MOVE TO ROA NO EARLIER THAN JANUARY 1, 2007?

A. As mentioned above, SB 7 as originally enacted stated that SPS was in a "competitive development area" and that SPS would proceed to ROA under a different track than applied to the other IOUs in Texas (other than El Paso Electric Company). (Please refer to original PURA 39.401 - .402 (and others) - since amended). Under original Section 39.402, SPS was to file a transition to competition plan by December 1, 2000, which SPS did do in Docket No. 23345. In a nutshell, SPS's plan stated that it had joined the SPP's Open Access Transmission Tariff and it had also joined the Midwest ISO as a member, supporting the requirement for SPS to join an Independent Organization. SPS further stated that it would divest generation to satisfy the PURA market power concerns, and unbundle as of January 1, 2002 as required by SB 7. SPS had agreed to divest its generation assets as part of a separate merger settlement with Xcel Energy—a major U.S. electricity and natural gas company with operations in 10 western and midwestern states. SPS's transition plan also indicated that SPS expected to be able to finalize the generation divestiture in late 2002 or early 2003 and, upon that divestiture, would satisfy the Qualified Power Region requirements in PURA, and could then commence ROA. SPS also committed to continue and expand its pilot program to 100% customer participation as of January 1, 2002.

On February 23, 2001, SPS filed a motion to abate its December 1, 2000 transition plan (filed in Docket No. 23345) because of pending legislation that would have a "profound impact" on the timing of SPS's transition. That legislation was HB 1692. The ALJ granted SPS's motion to abate on Feb. 27, 2001. HB 1692 became effective on June 15, 2001. That bill revised the SPS provisions in SB 7 to say, in part, that ROA in SPS's Texas service territory is delayed until at least January 1, 2007. SPS filed a motion to dismiss Docket No. 23345 on June 21, 2001; SOAH granted that motion on July 5, and the PUCT dismissed the docket on July 9, 2001.

Q. WHAT DO YOU CONCLUDE ABOUT SPS'S RESTRUCTURING EFFORTS?

A. What I would gather from all the procedural filings and ultimate delay granted to SPS was that, after February 27, 2001, there was limited activity to prepare for the retail pilot occurring when its transition plan docket was abated, although I understand that SPS remained active in the

ERCOT and PUCT collaborative and rulemaking processes until June 2001 with the passage of HB 1692. To reiterate, SPS was on a very different track, particularly by the end of February 2001, than was EGSI in its ROA requirements and implementation effort.

Q. WERE THERE ANY ASPECTS OF SPS'S TTC RECOVERY REQUEST THAT ARE RELEVANT TO THE COMPANY'S REQUEST?

A. Yes. Aspects of the SPS situation that are relevant to the EGSI situation include: the timing of the SPS readiness effort; and the rates that SPS indicated it used for outside services. I have used this information as a benchmark in an estimation model that I discussed and presented earlier in my testimony in Section III, Estimation Approach and Findings.

### 3. <u>ERCOT</u>

Q. PLEASE EXPLAIN THE BACKGROUND TO THE DEVELOPMENT OF THE ERCOT MARKET.

A. With the passage of SB 7 in 1999, ERCOT was required to consolidate into a single control area and operate as the statewide registration agent for retail customer enrollment and switching. During the fall of 1999, ERCOT developed bid documents to acquire the systems necessary to support the restructuring of the Texas retail electric market. Through a process involving the ERCOT Staff, PUCT Staff, ERCOT Market Participants, and a number of vendors, a system was designed to support the implementation of the ERCOT protocols which define the ERCOT market. System design began in March 2000, and systems were developed and built by January 1, 2001, at which time system testing was initiated. Market Trials began on April 1, 2001, and the ERCOT market was initiated for retail pilot purposes on July 31, 2001. This timeline was included in ERCOT's 2001 Readiness Update, attached to my testimony as Exhibit VGC-3, ERCOT System Overview.

Q. WAS THE COMPANY AFFECTED BY THE ERCOT MARKET TIMELINE?

A. Yes. EGSI was largely subject to the rules and interface requirements developed through ERCOT stakeholder processes and ERCOT working group meetings. As market rules evolved for the ERCOT retail market, functionality and system specifications were modified. The Company was required to comply with the testing plan, implementation timeline, and release schedule driven by ERCOT. Furthermore, any manual workaround, system change, or transaction upgrade that was required to interface with ERCOT as the central registration agent had to be secondarily developed by IOU and REP systems, including the Company, and tested and certified accordingly.

Q. WHAT ARE THE MAJOR ATTRIBUTES OF THE RETAIL MARKET IN TEXAS?

A. Numerous computer and communications systems comprise the foundation of the retail market. The market design in Texas emphasized creating a single, centralized clearinghouse for retail transactions with electronic exchange of information among market participants. ERCOT developed standard protocols for the electronic transmission of information among REPs, utilities, and itself, Texas SET. ERCOT and market participants relied primarily on EDI for electronic communications. The formal definition of EDI is "the interchange of structured data according to agreed upon message standards between differing companies' computer systems, via electronic means."

Q. WHAT IS TEXAS SET?

A. To support the exchange of data needed to operate the new electric market in Texas, new or modified standards had to be developed. These standards are known as Texas Standard Electronic Transactions or Texas SET. Texas SET standards were defined using existing EDI transactions through a stakeholder process. Texas SET includes defined standard electronic codes that enable and facilitate the processes of customer choice, such as customer registration, invoicing, service order, usage/consumption reporting, payment order, customer information, and confirmation of receipt. Revised versions of Texas SET have been developed since the inception of the pilot project to support additional business processes and functions. Since the inception of retail choice in

Texas, the EDI transaction codes, particularly those related to customer registration ("814s") and usage information ("867s"), and other technical jargon have become a commonly understood lexicon used by the market participants and ERCOT.

Q. ARE ALL IOUs IN TEXAS REQUIRED TO UTILIZE TEXAS SET?

A. All in ERCOT, plus it was also necessary for EGSI alone of the non-ERCOT IOUs to continue to maintain its interconnection with the ERCOT registration agent beyond December 31, 2001 through Texas SET because its target date for ROA, while delayed, continued to be in the near-term. During the pilot project from June 1 until December 31, 2001, a small portion of West Texas Utilities (WTU) in the Texas Panhandle and SWEPCO had the option of using Texas SET or processing transactions through ERCOT's web-based portal.

Q. WHAT IS ERCOT'S WEB-BASED PORTAL?

A. The ERCOT registration system portal was intended to be a low-cost alternative to Texas SET for switching transactions and metering information transactions.

Q. COULD THE COMPANY HAVE AVOIDED USING TEXAS SET BY USING THE PORTAL INSTEAD?

A. No. There are three primary reasons. First, given the number of customers that were managed and maintained through the registration system anticipated for EGSI (over 380,000), the portal functionality would not have supported the volume of activity required to complete a customer switch request. Second, metering information transactions were not supported on the portal during the pilot. The Company was required to provide historical and monthly consumption data (*i.e.,* meter reads) to REPs using a Texas SET 867 transaction. Thus, the Company was already required to maintain Texas SET certification for this purpose alone. Third, once the pilot was operational, availability of the portal was sporadic. When the portal was available, its use was cumbersome, often requiring multiple submissions of transactions.

Q. WHAT ATTRIBUTES OF RETAIL CHOICE IN TEXAS ARE DIFFERENT FROM OTHER REGIONS?

A. In Texas, ERCOT performs functions in the retail market that are performed by the transmission and distribution utilities in some other states that have introduced retail competition. A key element in the design of the ERCOT retail market was to use a neutral third party to perform tasks related to the switching and settlement functions. In this case, ERCOT is the neutral third party. ERCOT also performs key tasks like load profiling and centralized data aggregation for customers within the ERCOT region, but not outside of ERCOT within Texas. ERCOT is the only region in the nation with a model that centralizes retail enrollment and switching, and is the only region where end use consumption data is profiled and aggregated by an entity other than the distribution utility.

In addition to being the only state with centralized customer switching and registration functions, Texas also has a more complex market structure than other states and, therefore, market participants undergo more complex testing and certification. For example, in 2001, to complete a single switch request involving one ESI ID (that is, a single retail customer) one REP and one Transmission and Distribution Service Provider ("TDSP"), there were 16 Texas SET (EDI) transactions. In other states, this single switch request with the same number of parties would involve nine EDI transactions.

Q. IN ADDITION TO MORE COMPLEX RULES, ARE THERE OTHER FACTORS THAT MAKE PARTICIPATION IN THE TEXAS RETAIL PILOT COMPLICATED?

A. Yes. Since the inception of retail choice in ERCOT, which includes the requirement under SB 7 for ERCOT to provide centralized registration and customer switching functionality statewide, there have been 13 test flights to implement and upgrade Texas SET functionality. Five of these test flights have involved new versions of Texas SET functionality, requiring participation of all Market Participants. ERCOT has maintained statistics on Texas SET testing since its October 2001 ("1001") test flight. The chart below summarizes statistics gathered from various ERCOT Retail Market Subcommittee reports since October 2001. As Company witness Manasco discusses in his testimony, EGSI participated in five test flights over the five year time span: 1.3 in July 2001 (not summarized in the table); 1.4 beyond October 2001, 1.5 through April 2003, 1.6 through January 2004 and 2.0 through the June 2004 timeframe. The table below illustrates the magnitude of testing, market participant interfaces, and, in later test flights, the volume of transactions that needed to be managed for each test flight.

Table 2 – Texas SET Test Flight Statistics

| | 1001 | 0702 | 0902 | 1102 | 0403 | 0703 | 1003 | 0104 | 0504 | 0904 | 0105 | 0405 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TX SET Version | 1.4 | 1.4 | 1.4 | 1.4 | 1.5 | 1.5 | 1.6 | 1.6 | 2.0 | 2.0 | 2.0 | 2.0 |
| New REPs | 26 | 3 | 3 | 6 | 5 | 0 | 10 | 13 | 6 | 13 | 7 | 15 |
| Existing REPs in New Territories | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 3 | 6 | 7 | 5 | 1 |
| Existing REPs testing New Functinality | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 22 | 39 | 3 | 1 | 0 |
| Bank Changes | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 1 | 1 | 2 | 0 | 5 |
| EDI Provider Change | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 1 | 2 | 2 | 2 | 2 |
| Total Tasks | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 16,000 | 28,669 | 9,643 | 4,060 | 8,023 |
| TDSP Sytems involved | 6 | 2 | 2 | 2 | 7 | 4 | 7 | 6 | 7 | 5 | 6 | 6 |
| Restarted Scripts | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 0 | 4 | 0 | 0 | |
| Completed on time | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | |

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS TABLE?

A. The primary conclusion to be drawn is that changes and additions continued (and in fact continue today) in the ERCOT market, even after ROA started in that market. Not only were the Texas SET versions continuing to change, testing volume (total tasks) were significant in each test flight, and the test flights occur frequently in a given year. This table demonstrates that all market participants, including EGSI during its pilot