Q83. WHAT OVERALL CONCLUSION DO YOU DRAW FROM YOUR SUPPORTING EVIDENCE REGARDING THE TRANSMISSION OPERATIONS CLASS OF AFFILIATE SERVICES?

A. From the evidence presented, I conclude that the products and services provided by the Transmission Operations Class of affiliate services are necessary because they support the operations of ETI's transmission system and ensure compliance with the applicable codes and standards. I conclude that the expenses for this cost class are reasonable because ETI's total transmission O&M costs compare favorably to other utilities, as demonstrated by the benchmarking analyses discussed above. Finally, the affiliate charges associated with these products and services are billed at a cost and at a rate no higher than the charges to the other affiliates for the same or similar services. In addition, these services are not duplicated by ETI or any other affiliate or third party.

IV. TRANSMISSION CAPITAL PROJECTS

A. Overview of Transmission Capital Projects

Q84. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I describe the capital additions to rate base for transmission plant closed to plant-in-service since the end of the test year in Docket No. 39896; that is, from July 1, 2011 through the end of the test year in this docket – March 31, 2013. Transmission plant-in-service capital additions include those made in the categories of General Plant, Intangible additions, and Transmission Plant for the Transmission Function. The breakdown for each of these categories is shown in Table 7.

Table 7

Transmission Capital Projects Summary by Category		
July 1, 2011 – March 31, 2013	DOLLARS CLOSED TO PLANT	PERCENT
General Plant	$1,071,966	1.7%
Intangible	$3,720,089	5.8%
Transmission Plant	$59,149,808	92.5%
Total Transmission Function	**$63,941,863**	**100.0%**

Q85. WHAT IS THE TOTAL AMOUNT OF CAPITAL ADDITIONS FOR TRANSMISSION PROJECTS THAT YOU ADDRESS IN THIS PROCEEDING?

A. The total amount of transmission capital additions I address is $63,941,863. The specific projects included in this amount are detailed in Exhibit MFM-11 attached to this testimony.

Q86. PLEASE DESCRIBE THE INFORMATION PROVIDED ON EXHIBIT MFM-11.

A. Exhibit MFM-11 is a spreadsheet that details the specific projects including the total amount of capital addition closed to plant from July 1, 2011 through March 31, 2013. It is organized by asset class, which includes General Plant, Intangible additions, and Transmission Plant. Each project can be identified by a specific project code and project code description, which provides an explanation for the expense. The exhibit includes the following information under column headers:

Column A	Project Code
Column B	Project Code Description
Column C	Asset Class
Column D	In service Date
Column E	Asset Location Description
Column F	State Location
Column G	Business Unit ("BU")
Column H	Non-Affiliate Charges Excluding Capital Suspense and Reimbursements
Column I	Reimbursements
Column J	Represents capital suspense overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function charges their capital suspense to a "Capital Suspense" project, which is then allocated out to the appropriate capital projects. Capital Suspense costs and the subsequent allocation is separated by BU and function combination to more accurately match such costs on the actual projects worked on for each function within a BU.
Column K	Represents the portion of capital suspense overhead costs (in Column J) from an affiliate.
Column L	Represents the portion of capital suspense overhead costs (in Column J) that are charged to the project by ETI employees.
Column M	Represents charges incurred by the ESI service company and allocated out to the appropriate BUs based on the ESI billing method assigned to the project plus loaned resource charges incurred at one

BU and charged to another BU for services rendered on behalf of that BU.

Column N — Represents the total affiliate portion of the charges included in Column O, and is the total of Columns K and M.

Column O — Represents the total amount of capital additions closed to plant in service.

Q87. PLEASE DESCRIBE THE MAJOR TYPES OF TRANSMISSION ADDITIONS TO RATE BASE.

A. From July 1, 2011 through March 30, 2013, ETI added $63,941,863 to plant-in-service for transmission as shown in Exhibit MFM-11. In this testimony, I discuss in detail the 18 transmission-related projects with costs exceeding $1M. These projects constitute 72% of the total transmission additions to ETI's rate base. Information regarding the remaining 28% of additions is contained in Exhibit MFM-11.

Transmission projects can generally be categorized as one of seven types: Reliability, Revenue, Failure, Infrastructure, Mandated, Transmission Service, and Other. Each type is described below.

Reliability – A project (i) that is needed for the continued uninterrupted operation of the transmission system to prevent an operational deficiency, or (ii) that is the result of load growth. Examples of projects undertaken to address operational deficiencies include the shielding of lines for lightning protection, the addition of switches/circuit breakers for quicker or easier restoration of customers, the addition of lines for improved reliability, and the replacement of obsolete or deficient equipment or hardware. Examples of projects undertaken to address load growth include the re-conductoring of overloaded lines, the addition of transformer capacity to a substation for area load growth, the addition of substation capacitor banks, and the construction of a new line into an area to increase import capacity.

Revenue – A project required (i) to connect a new customer to the transmission system, (ii) to provide capability to serve increased load for an existing customer, or (iii) for the addition of facilities to be fully covered under facility charges. The majority of these projects require the customer to provide a payment in the form of a monthly facilities charge. Examples include the addition of a new substation for an industrial customer, the addition of a new transmission line for a specific customer, or an increase of transformer capacity at an industrial site. All are required to meet specific load requirements of individual customers.

Failures – A project necessary to replace or repair failed equipment. Examples include the rewinding or replacing of a failed transformer; and replacing damaged poles, insulators, breakers, shield wire, etc.

Infrastructure – A project that provides for replacement of antiquated, technologically-outdated equipment or equipment no longer supported by the manufacturer. Examples include certain types of lightning arresters, batteries, relays, or any obsolete equipment.

Mandated – Projects that must be funded and completed without delay due to contractual agreement, law or regulatory requirements. Examples include moving facilities at the request of the highway department, adding/modifying facilities under a contractual agreement, independent power producer ("IPP") work for which the IPP receives transmission credits, and reimbursable projects for interconnecting utilities.

Transmission Service – Transmission upgrades necessary to designate generation as a network resource or accommodate point-to-point transmission service.

Other – Projects that are needed to support the operation of the electrical system but are not a direct part of the electrical system. Examples include facility additions, the funds used to replace or purchase new tools required for construction and/or maintenance, and general and intangible additions that were specifically related to transmission functions.

B. Discussion of Specific Transmission Capital Projects

Q88. PLEASE DESCRIBE THE 18 TRANSMISSION CAPITAL PROJECTS THAT YOU INDICATED INCURRED THE HIGHEST TOTAL COSTS.

A. Table 8 lists the 18 transmission capital projects that incurred the majority of the costs, in order of highest-to-lowest cost. The projects are listed by Project Code, as seen in Exhibit MFM-11.

Table 8: 18 Highest Transmission Capital Projects by Cost

	Project Code	Description	Asset Class	Type	Dollars Closed to Plant
1	F1PPU75349	Grand Gulf Uprate TSR 206 MW GGU	Transmission Plant	Transmission Service	$ 11,882,194
2	F1PPU75446	Construct ETI-ERCOT Emergency Tie	Transmission Plant	Mandated	$ 4,029,966
3	F1PCUX5009	Replace Transformer at Metro Substation	Transmission Plant	Reliability (Distribution)	$ 3,039,707
4	F1PPU50694	Purchase 230/138kV Autotransformer at Mid-County Substation	Transmission Plant	Failures	$ 2,913,945
5	F1PPU50717	Purchase 500/230kV Autotransformer for Cypress Substation	Transmission Plant	Failures	$ 2,866,178
6	F1PPU50537	Land Purchase for Ponderosa Switching Station	Transmission Plant	Reliability	$ 2,834,082
7	F1PCUD0556E	Distribution Substation Equipment Failures	Transmission Plant	Failures	$ 2,324,994
8	F1PCUD0551E	Transmission Equipment Failures Blanket	Transmission Plant and Intangible	Failures	$ 2,284,715
9	F1PPUD0074E	EMS/SCADA Reconfigure Host Plan	Intangible	Reliability/ Infrastructure	$ 1,920,757
10	F1PPU50623	ETI Spare Transformer	Transmission Plant	Failures	$ 1,776,367
11	F1PCUD0279E	Transmission Line Program Blanket	Transmission Plant	Reliability/ Infrastructure	$ 1,655,773
12	F1PPUD0129E	Skylining Tree Hazard Blanket	Transmission Plant	Reliability	$ 1,536,145
13	F1PPSTORM3	Hurricane Ike Restoration	Transmission Plant	Failures	$ 1,506,433
14	F1PPU75486	NERC Alert ETI Line Mitigation	Transmission Plant	Infrastructure/ Mandated	$ 1,279,375
15	F1PPU50636	System Substation Facility Upgrade Project	Transmission Plant	Reliability/ Infrastructure	$ 1,136,067
16	F1PCUD0122E	Wood Pole Replacement	Transmission Plant	Infrastructure	$ 1,059,723
17	F1PPUD0238	NERC Alert LIDAR Inspection	Intangible	Reliability/ Mandated	$ 1,032,652
18	F1PCUD0117E	Distribution Substation Relay Improvement Blanket	Transmission Plant	Reliability/ Infrastructure	$ 1,024,611
				TOTAL	$ 46,103,683

1. **Project F1PPU75349: Grand Gulf Uprate (206 MW Transmission Service Request).** ESI's System Planning and Operations ("SPO")

organization requested, on behalf of System Entergy Resources, Inc., an Arkansas Corporation, to designate 206 MW from the Grand Gulf Station Generation Plant as a 'Network Resource' from June 1, 2012 to June 1, 2042 as part of a transmission service request ("TSR"). The ICT determined that adding this incremental generation to the Entergy Transmission System would not be feasible without making improvements across the transmission systems of ELL, EGSL, EMI, and ETI. The portfolio of projects within ETI includes:

1. Hartburg – McLewis 230 kV Transmission Line – Upgrade the line capacity to 740 MVA.
2. Inland Orange 230 kV Substation – Replace jumpers from transmission lines to bus.
3. Hartburg 230 kV Substation – Replace jumpers from transmission lines to bus.
4. McLewis 230 kV Substation – Replace line switches and jumpers from transmission lines to switches.

The total cost of this portfolio of projects was $11,882,194.

2. **Project F1PPU75446: Construct ETI-ERCOT Emergency Tie.** The purpose of this project was to provide a transmission interconnection to tie part of the ETI transmission system in the College Station area to the Electric Reliability Council of Texas, Inc. ("ERCOT") system under emergency conditions. This proposal resulted from two bills passed during the 2009 Texas legislative session (HB 1831 and SB 1492)

which gave certain authority to the PUC during an emergency and required a study to identify the need for emergency power and actions to prepare for emergency power. The total cost of this project was $4,029,966.

3. **Project F1PCUX5009: Replace Transformer at Metro Substation.** The purpose of this project was to remove the Metro T1 75 MVA transformer and install a new 100 MVA transformer to serve area load growth. Metro Substation had one 75 MVA transformer (T1) and one 100 MVA transformer (T2). By 2013, transformer T1 was projected to be loaded by 110% of its nameplate rating during peak conditions. Much of the load increase is due to spot loads in the Town Center area of The Woodlands, Texas. Some of these loads include two hotels, a condominium tower, two office buildings, and a large apartment complex. The total cost of this project was $3,039,706.

4. **Project F1PPU50694: Purchase 230/138 kV Autotransformer for Mid County Substation.** ETI's Mid County Substation autotransformer failed during operation on May 2, 2011. This project's purpose was to purchase a new 230/138 kV 180/240/300 MVA three-phase autotransformer for replacement of the failed autotransformer. The total cost of this project was $2,913,944.

5. **Project F1PPU50717: Purchase a 500/230 kV Autotransformer for Cypress Substation.** ETI's Cypress Substation autotransformer failed during operation on September 1, 2011. This project's purpose was to

purchase a new 500/230/13.8 kV 150/200/250 MVA single-phase autotransformer for replacement of the failed autotransformer. The total cost of this project was $2,866,177.

6. **Project F1PPU50537: Land Purchase for Ponderosa Switching Station.** As determined by reliability planning studies to comply with NERC Reliability Standard TPL-002, it was determined that, under the contingency loss of the Lewis Creek-to-Longmire 138 kV transmission line (line 596), overloading of the Tubular-to-Dobbin 138 kV transmission line segment could occur. In addition, potential unacceptable voltage levels at Navasota, Tubular, Dobbin, Fish Creek, Spring Branch, and Longmire substations may arise for various N-1, G-1 scenarios.[9] The purpose of building this switching station is to mitigate these risks. The scope of this project is to install a 138 kV switching station (4-breaker ring bus) where the Longmire-to-Fish Creek 138 kV transmission line parallels the Conroe-to-Woodhaven 138 kV line (lines 96 and 112), cut both lines into the switching station, and relocate Line 569 (Lewis Creek-to-Alden 138 kV). This project will mitigate the single-contingency loss of the source from Lewis Creek and provide long term benefits in the Conroe area. Land was purchased in order to provide a location to construct the Ponderosa

[9] N-1, G-1 scenarios are outage scenarios in which a single transmission line component and a single generator are concurrently out of service.

Switching Station. The total cost of this land purchase was $2,834,082.

7. **Project F1PCUD0556E: Distribution Substation Equipment Failures.** This project's purpose was to replace failed substation equipment such as small instrument transformers, regulators, circuit breakers, circuit switches, capacitor banks, bushings, switches, bus, structures and more. Replacement is generally associated with service/capacity restoration. The total cost of ETI's share of this project was $2,324,993.

8. **Project F1PCUD0551E: Transmission Equipment Failures Blanket.** This program funds the repair and/or replacement of failed transmission line components, such as poles, insulators, cross arms, shield wire, conductor, cross braces, and line switches. Additionally, this program funds the capital requirements to repair and/or replace property damaged during minor storm events. The objective of this program is to respond to material failures that occur due to degradation, storm events, public-inflicted damage and other miscellaneous modes of failure. The total cost of ETI's share of this project was $2,284,714.

9. **Project F1PPUD0074E: EMS/SCADA Reconfigure Host Plan.** This project's purpose is to design, purchase, install, and implement software and hardware for the Emergency Management Systems of the EOCs' Transmission Operations Centers, Distribution Operations

Centers, and System Operations Center. These computer systems replace obsolete hardware and software and provide redundant computer systems for the Transmission System's critical control applications, and address the NERC Reliability Standard CIP-009, which includes a requirement for all critical control centers that control the reliability of the electrical grid have backup capabilities. The total cost of ETI's share of this project was $1,920,757.

10. **Project F1PPU50623: ETI Spare Transformer.** A 230/69 kV autotransformer failed during operation on September 16, 2005, immediately following Hurricane Katrina. An ETI spare 230/69 kV, 120/160/200 MVA LTC autotransformer was used as its replacement. The purpose of this project was to purchase a new 230/69 kV, 120/160/200 MVA LTC autotransformer to replace the spare transformer that was utilized for the failure. The total cost of this project was $1,776,367.

11. **Project F1PCUD0279E: Transmission Line Program Blanket.** This program includes corrective maintenance activities, which involve replacement of "units of property." Work includes those tasks identified through aerial and ground inspections. Climbing or aerial inspections are performed on each line cyclically identifying needed repairs. The deficiencies include damages and structural degradation due to age. Problems resulting from line outages are logged in the LWMS

database for repair. The total cost of ETI's share of this project was $1,655,772.

12. **Project F1PPUD0129E: Skylining Tree Hazard Blanket.** A high percentage of vegetation-related outages are due to vegetation growth outside of the EOCs' rights-of-way. This program is managed by the T&D Asset Management department and is aimed at shaping the off-ROW perimeter to reduce off-ROW vegetation contact. The total cost of ETI's share of this project was $1,536,145.

13. **Project F1PPSTORM3: Hurricane Ike Restoration.** This project was necessary to restore transmission line and substation facilities damaged by Hurricane Ike, a strong Category 2 hurricane that made landfall near Galveston, Texas on September 13, 2008. Restoration projects placed in service from July 1, 2011 to March 31, 2013 included replacing relays and an RTU at the Sabine Substation, replacing relays and motor operators at the Gulfrich Substation and replacing a leased fiber optic line at the Carroll Street Park Substation. From July 1, 2011 through March 31, 2013, ETI's total cost for Hurricane Ike repairs captured under this budget item was $1,506,432.

14. **Project F1PPU75486: NERC Alert ETI Line Mitigation.** This project is one of two funding projects that capture the costs to comply with an October 2010 NERC Facilities Ratings Alert requiring all utilities to verify that all Bulk Electric System transmission lines operating at 100 kV and above remain within intended design tolerances to support

the assigned ratings. Following identification of needed remediation under Project F1PPUD0238, this funding project captured the costs for scoping, engineering time, construction, etc. for the transmission line and distribution wires capital work or other infrastructure improvements performed within ETI's service territory that were required to comply with the Facilities Ratings Alert. The total cost of this project was $1,279,374.

15. **Project F1PPU50636: System Substation Facility Upgrade Project.** This project was necessary to upgrade under-rated substation equipment on ETI's transmission system. The total cost of this project was $1,136,066.

16. **Project F1PCUD0122E: Wood Pole Replacement.** Approximately 75% of the structures supporting the EOCs' transmission lines are of wood pole type with an average age of over 35 years. Wood pole inspections have identified more than 3,000 poles needing replacement or repair. This program funds the repair or replacement of poles no longer meeting NESC strength requirements. Each year, approximately 300 additional poles are identified for replacement or repair. The cost to replace a pole ranges from $4,000 to $15,000 per structure. The total cost of ETI's share of this project was $1,059,723.

17. **Project F1PPUD0238: NERC Alert LiDAR Inspection.** This project is one of two funding projects that capture the costs to comply with an October 2010 NERC Facilities Ratings Alert requiring all utilities to

verify that all Bulk Electric System transmission lines operating at 100 kV and above remain within intended design tolerances to support the assigned ratings. This funding project uses a combination of LiDAR radar technology, aerial inspections, and manual surveys in order to collect data needed for assessments and remediation. Data analysis is then performed to determine capital improvement plans for corrective actions. Once approved, capital improvements are completed to finalize remediation under Project F1PPU75486. The total cost of ETI's share of this project was $1,032,651.

18. **Project F1PCUD0117E: Distribution Substation Relay Improvement Blanket.** This project involves the replacement of relay systems and related minor components to resolve system protection performance and coordination/settings issues arising from obsolete technology, incompatibility with related scheme components, and system or operating procedure changes. This project also provides required funding to meet SERC relay misoperation mitigation plans filed semi-annually. It reduces customer interruption and customer minutes associated with relaying misoperations. It also reduces O&M spending by utilizing self-diagnostic technology. The total cost of ETI's share of this project was $1,024,611.

C. Transmission Capital Projects Were Reasonable and Necessary

Q89. ARE THE CAPITAL PROJECT COSTS IDENTIFIED IN EXHIBIT MFM-11 PROPERLY INCLUDED IN RATE BASE IN THIS PROCEEDING?

A. Yes. The $64 million in expenditures were reasonable and necessary to construct transmission capital projects required to continue providing reliable service to ETI's customers. These investments are for ETI substations and transmission lines that are required to serve customers in ETI's service territory.

Q90. ARE THESE ITEMS USED AND USEFUL IN PROVIDING SERVICE?

A. Yes. Each of the items shown on Exhibit MFM-11 is in-service and being used to provide service to ETI's customers or is a necessary part of planned investments that will be operational within ten years under a definite plan.

Q91. ARE ANY AFFILIATE COSTS INCLUDED IN THE REQUESTED CAPITAL ADDITIONS TO RATE BASE?

A. Yes. Affiliate costs totaled $10,882,791 of the requested capital additions of $63,941,863 for transmission projects shown in Exhibit MFM-11.

Q92. WHY WERE THESE AFFILIATE COSTS NECESSARY?

A. These costs are the result of ESI employees providing the design and construction management of specific capital projects for ETI's transmission system, as well as for general planning, design, design engineering services, project management, and construction management. These affiliate charges are for services that benefit the entire Entergy Transmission System, including the ETI system, and are necessary to meet the current and future needs of the EOS' customers.

Q93. HAVE YOU DISCUSSED THE REASONABLENESS OF THE AFFILIATE CHARGES IN THIS TESTIMONY?

A. Yes. In the affiliate charges portion of this testimony supporting the Transmission Operations affiliate cost class, I discussed the necessity and reasonableness of charges by ESI employees, including budget and cost controls, and some of the efficiencies captured through process improvements and technology advances. That discussion is applicable to the types of costs that are represented in the affiliate costs included in the capital additions discussed above. Moreover, the affiliate charges for capital costs are made under the same cost-causative system of billing methods previously discussed. Accordingly, the affiliate charges for capital costs are at-cost and at a rate no higher than the charges made to other affiliates for the same or similar services.

Q94. WERE THE NON-AFFILIATE COSTS ADDED TO RATE BASE REASONABLE?

A. Yes. The non-affiliate costs are largely composed of capitalized ETI direct-labor costs, and the cost of materials, subcontractors and independent contractors, and land rights procurement. The reasonableness of the compensation and benefits program associated with the direct-labor costs for ETI employees is addressed in the testimony of Company witness Raeder. As discussed below, with regard to materials and subcontractors, ETI purchases materials and secures subcontractors in a manner that ensures that reasonable costs are incurred. Similarly, as discussed below, the interests in real property that are necessary to site these transmission projects are procured in a manner that ensures reasonable costs are incurred.

Q95. WHAT PROCESS AND BUDGET CONTROL DOES ETI HAVE IN PLACE TO ENSURE THAT MATERIALS ARE PROCURED AT A REASONABLE COST?

A. As explained in more detail in the Direct Testimony of Company witness Reginald T. Jackson, ETI has a number of cost control measures in place. First, all materials purchases are made through arm's-length transactions from non-affiliated parties in a competitive market. ETI chooses among several suppliers for comparable materials. For some commonly used materials and equipment, ETI has negotiated alliance agreements with suppliers. Such alliances are based on a competitive bid process that takes place on a regular basis. All other materials are procured though a competitive bid process from a list of approved suppliers. ETI has also used reverse auctions to bid commodity-type products. All alliance agreements and bid results are checked against market indices to ensure that the pricing is reasonable and prudent.

Q96. WHAT STEPS DOES ETI TAKE TO ENSURE THAT SUBCONTRACTORS AND INDEPENDENT CONTRACTORS ARE PROCURED AT A REASONABLE COST?

A. As is the case with materials, ETI has a number of cost-control measures in place to ensure that subcontracting costs are reasonable. The primary method of ensuring reasonable costs for contractors is through the utilization of a competitive bid process and fixed-price contracts. ETI ensures that costs stay within the estimates by providing inspectors/representatives on all jobs that involve the construction of facilities in order to ensure that ETI's contractors are performing quality work and keeping within the scope of all contracts. ETI requires documented change requests to be approved by management before any work outside the scope of a contract is performed. In some cases, ETI has negotiated alliance agreements with contractors. These alliances are the result of a competitive bid process and are re-bid on a regular basis. In the case of a contract alliance, ETI also maintains and uses the right to bid individual contracts during the life of the alliance to ensure that the alliance is still a reasonable and competitive vehicle for conducting business.

Q97. WHAT MEASURES ENSURE THAT REAL PROPERTY RIGHTS ARE OBTAINED AT A REASONABLE COST?

A. Rights in real property are purchased from third parties through arm's-length transactions based on the market value of the land. If necessary, appraisers are retained to determine the reasonable value. If the price demanded by a landowner is unreasonable, ETI has the option to seek condemnation of the property and have a court set the value of the property. If feasible, ETI acquires only an easement from property owners (as opposed to acquiring outright title to the land) to reduce the cost of the acquisition.

Q98. WHAT MEASURES OR PROCESSES DOES ETI HAVE IN PLACE TO ENSURE THAT THE CONSTRUCTION OF A TRANSMISSION FACILITY PROCEEDS IN A TIMELY MANNER AND AT A REASONABLE COST?

A. As previously discussed, ESI's Engineering and Construction department provides project management on the construction of all transmission facilities. Project Management involves a number of cost-control measures. First and foremost, construction of transmission facilities is done predominantly via a firm, fixed-price contract or through the use of an alliance agreement. The contract itself helps ensure reasonableness through the bidding process and serves as a cost-control instrument. To ensure that ETI's contractors are working safely, performing quality work and building within the scope of all contracts, ETI utilizes inspectors/representatives on all jobs that involve the construction of facilities. The inspectors keep daily job logs for use when approving contractor timesheets or invoices. ETI also utilizes a change-control process to document and approve all changes to the construction of transmission facilities before those changes take place. Finally, project schedules and estimates, and the tracking and management of each, are also used to ensure reasonable cost.

Q99. PLEASE EXPLAIN THE BUDGETING AND COST CONTROL PROCESSES THAT SUPPORT THE REASONABLENESS OF THE TOTAL ETI TRANSMISSION CAPITAL COSTS TO BE ADDED TO RATE BASE.

A. As explained earlier, budgeting processes are employed that build from budgets prepared by each EOC, such as ETI, and more specifically, from budgets prepared by functional organizations whose costs are reflected on a legal-entity basis. The Transmission Organization prepares a budget reflecting ETI transmission capital projects. Once the budget is approved, that budget is periodically compared to actual spending levels for the same organization and the same entity. The Transmission Organization monitors actual spending compared to budget through the following reports and measures, at the time intervals indicated, to assist in controlling costs:

- Monthly – Capital budget to actual report by legal entity with explanations of the variances. This document reports current-month spending versus current-month budget, current-month spending versus prior-year same-month spending, year-to-date spending versus year-to-date budget, and year-to-date spending versus year-to-date spending prior year.
- Monthly/Quarterly – Capital current year-end projection (present estimate) by legal entity.
- Monthly – Construction work in progress at the detail capital work order level, including the preparation of reports showing which work orders are past the estimated in-service date and field updates on a monthly basis for all projects that are in-service or updates on the estimated in-service date for those projects that have been delayed.

Q100. EXPLAIN HOW THE BUDGET REPORTS ARE UTILIZED.

A. On a monthly basis, budget versus actual reports are monitored by each department within the Transmission Organization. Costs are analyzed by resources (*e.g.,* labor, material, contract labor, and employee expenses), which are tracked through the accounting systems. Any significant variances are reviewed, and updated spending plans are implemented. The Transmission Organization's updated plan is submitted to Utility Operations with any changes to the original plan.

Q101. BASED ON ALL OF THIS INFORMATION, HAVE YOU REACHED A CONCLUSION REGARDING THE REASONABLENESS OF ETI'S CAPITAL ADDITIONS?

A. Yes. It is reasonable to include these capital costs in ETI's rate base in this case because these investments are necessary for ETI to provide transmission services to its customers. These capital additions to ETI's transmission system are used and useful in providing service to its customers. In addition, the construction projects were carefully supervised, and procedures were followed to ensure costs of materials, contractors, and real estate were reasonable.

V. DEMAND AND ENERGY LOSS FACTORS

A. Development of Transmission and Distribution Demand and Energy Losses

Q102. WHAT ARE LOSS FACTORS, AND WHAT IS THE PURPOSE OF CALCULATING TRANSMISSION AND DISTRIBUTION SYSTEMS' DEMAND AND ENERGY LOSSES?

A. In broad terms, loss factors represent energy consumed during the process of moving the power from generation to load. Because transmission and distribution losses are so widespread and vary depending on distance and grid infrastructure, metered losses are not readily available. Instead they are usually estimated. The Transmission and Distribution Systems' demand and energy losses are calculated by the Energy Delivery Organization to enable the Rate Design group to develop allocation factors for use in the cost-of-service study. There are two types of losses: (1) demand loss, which is the increased generating capacity requirements necessary to meet the power consumption of a utility's customers (capacity demanded by customers); and (2) energy loss, which is the increased energy requirements over a certain period of time to meet the energy usage requirements of a utility's customers (energy consumption).

Q103. WHAT ARE TRANSMISSION AND DISTRIBUTION SYSTEM DEMAND LOSSES?

A. Demand losses result mainly from electrical impedance as power flows through transmission and distribution facilities. The demand losses add to the power generation requirements such that the total generation capacity output at the power plants must be greater than the total demand of the customers. Electric utilities generally analyze system demand losses during a system peak for a relevant time period. The total power generation requirements of ETI's power system are made up of its area generation and net power interchange.

Q104. WHAT ARE TRANSMISSION AND DISTRIBUTION ENERGY LOSSES?

A. Energy losses are electrical energy that must be generated in excess of customer demand in order to serve customer energy consumption.

Energy losses for a given time period are calculated by summing the instantaneous demand loss for the relevant time period.

Utilities cannot measure the instantaneous demand of all customers and do not have instantaneous demand meters on all components of the transmission and distribution network. Therefore, energy loss factors are estimated by using load descriptors such as the peak responsibility factor,[10] the coincidence factor,[11] the load factor,[12] and the loss factor.[13]

B. Development of Transmission and Distribution Demand Losses

Q105. PLEASE PROVIDE AN OVERVIEW OF HOW ETI DEVELOPED ITS DEMAND LOSS FACTORS.

A. ETI utilizes a top-down approach to estimate its demand loss; that is, it analyzes demand losses for the highest voltage level in the system and then for each successively lower voltage level. The Company calculated demand loss factors for the analysis period, April 1, 2012 through March 31, 2013. The demand loss analysis that I sponsor estimates

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[10] The peak responsibility factor is the ratio of the on-peak load for each component of the transmission and distribution system to the peak design ("rated") load for each component of the transmission and distribution system.

[11] The coincidence factor is a ratio of the maximum demand coincident with the Company's system peak for a specified group of customers to the sum of the individual maximum non-coincident demands of the members of such group.

[12] Load factor is calculated by dividing the energy consumed for a specified time period by the product of the number of time units for such specified time period and the peak demand that occurred during such time period.

[13] Loss factor is defined as the energy loss during a specific time period divided by the product of the specific time period and the peak demand loss.

demand losses for four voltage levels: (1) the transmission system at 230 kV and above ("bulk transmission system"); (2) the transmission system below 230 kV and above or equal to 69 kV ("local transmission system"); (3) the primary distribution system; and (4) the secondary distribution system.

ETI analyzes measured on-peak generation and net power interchange on the supply-side and the on-peak power demands of its customers for comparable time periods. On-peak power deliveries were estimated by using demand data for all locations equipped with interval recording demand meters installed for billing purposes and by using estimated hourly demands of customers who normally do not have hourly demand meters at their service location.

The average of the 12 monthly coincident peaks ("12 CP") during the analysis period is used to estimate demand losses. The Company's average 12 CP generation plus net power interchange for the analysis period was 3,494 Megawatt ("MW"), and the average 12 CP demand for the analysis period was 3,073 MW.

Q106. PLEASE DESCRIBE HOW THE COMPANY CALCULATES DEMAND LOSS FACTORS.

A. Transmission demand losses are determined by performing transmission load-flow simulations using the Power System Simulator for Engineering ("PSS/E") model for ETI's 12 CP in the analysis period. The demand losses of the bulk transmission system are the sum of average demand losses in the 500 kV, 345 kV and 230 kV systems. The demand losses of the local transmission system are the sum of average demand losses in the 138 kV, 115 kV and 69 kV systems. Distribution demand losses are calculated by the Simplified Calculation of Loss Equations ("SCALE") model developed by the Electric Power Research Institute ("EPRI"). SCALE uses the observed customer demand patterns to calculate demand losses for substation transformers, distribution primaries (feeders and laterals), distribution secondaries, and distribution transformers.

After the demand losses are estimated for all voltage levels, loss ratios for each voltage level are determined as the ratio of input power to the input power, less the demand loss calculated for each voltage level. The cumulative demand loss factor for a given voltage level is determined as the product of the loss ratio for each voltage level and the cumulative demand loss factor for the next lower voltage level.

Q107. HOW DID ETI ESTIMATE TRANSMISSION DEMAND LOSSES?

A. ETI uses the PSS/E transmission network load-flow analysis software to estimate demand losses for the transmission system. The results from the PSS/E software show that transmission system losses accounted for 42 MW of the total system losses: 11 MW were lost in the bulk transmission system, and 31 MW were lost in the local transmission system (rounded and as reflected on Exhibit MFM-12). Therefore, the remaining 162 MW of losses were attributable to losses in the distribution primary and distribution secondary systems. These losses are reflected on Exhibit MFM-12.

Q108. PLEASE DESCRIBE THE PSS/E MODEL.

A. The PSS/E software, created by Power Technologies, Inc., is electric transmission system network simulation software used by many of the major utilities in the world to simulate power flows. PSS/E is an integrated, interactive program for simulating, analyzing, and optimizing power system performance.

Q109. PLEASE DESCRIBE HOW SUBSTATION DEMAND LOSSES ARE ESTIMATED.

A. Substation demand losses are estimated for the average of 12 CP for the test period. Only substation transformer losses are considered in calculating substation losses. Additional losses, such as in the substation transformer cooling fans, the control equipment, the feeder bay equipment, the lightning arrestors, and the capacitor banks, are minimal and not considered. Test data for a representative group of transformers are studied. The load loss characteristics of the transformers under no-load and on-peak conditions are used in developing the loss estimation.

The demands measured in megawatts on the transformers are determined from the transmission deliveries to the substation (*i.e.*, the net input into the transmission system less the sum of deliveries to bulk and local transmission customers and bulk and local transmission system losses). The total substation transformer loss is determined by multiplying the sum of the no-load losses per transformer and on-peak transformer losses per transformer by the number of transformers on the system.

The substation transformer demand losses for the bulk transmission system are estimated to be 3 MW, and the substation transformer demand losses for the local transmission system are estimated to be 30 MW, for a total of 33 MW (rounded and as reflected on Exhibit MFM-12).

Q110. HOW WERE PRIMARY DISTRIBUTION DEMAND LOSSES ESTIMATED?

A. The primary distribution system is composed mainly of feeders and laterals.[14] The typical voltage of ETI's distribution primary system is 13.2 kV or 34.5 kV. The Company calculated losses separately for feeders and laterals.

[14] A feeder is a three-phase circuit that originates at a distribution substation. Feeders generally distribute power to laterals and provide three-phase service to large customers. A typical feeder consists of 3/4-inch diameter aluminum composite steel reinforced cable. A lateral is generally a single-phase circuit that branches from a feeder. Laterals distribute power to smaller customers.

The load injected into the distribution feeders was determined by subtracting the substation transformer losses from transmission supply. The average loss per feeder was determined for three-phase feeders.[15] The total feeder demand losses were estimated to be 87 MW for the analysis period. The equation used to calculate line losses for lateral distribution lines was the same as the equation used for feeders, except the Distribution Factor reflected the load diversity characteristics of lateral distribution lines. For the analysis period, the allocated demand loss for distribution laterals was 1 MW. The total primary distribution demand losses, including feeders, laterals, and other losses, were 91 MW (rounded and as reflected on Exhibit MFM-12).

Q111. HOW WERE SECONDARY DISTRIBUTION SYSTEM DEMAND LOSSES DETERMINED?

A. The secondary distribution system consists of many different components. There are the two major components of the secondary distribution system: distribution transformers and the secondaries (service drops from the distribution transformers to the service locations). The voltage of the

[15] The formula used to calculate feeder and lateral line losses was $L = I^2 * R *$ Distribution Factor. Where:

L = the average demand loss per feeder/lateral for the average of the 12 CP;

I = the average current on the feeder/lateral;

R = the average resistance for the feeder/lateral; and

Distribution Factor = a coefficient which describes the equivalent aggregated distribution along a distribution feeder or lateral. The Distribution Factor is 1.15 for feeders and for laterals.

secondary distribution system is typically 240 volts. Distribution transformer losses and the losses on secondaries were calculated for ETI's average of 12 CP. Both the no-load and load loss characteristics of a representative distribution transformer were used to calculate distribution demand losses.

For a secondary, the average on-peak current per secondary (240 volts) was determined from a representative sampling of ETI's secondary lines. The average on-peak demand loss per secondary was determined based upon the average current and the average resistance for the line.[16] The total secondary demand loss was determined by multiplying the average loss per secondary by the number of secondaries. The estimated secondary line loss was 4 MW.

The total secondary distribution transformer demand loss was determined by summing the demand loss under no-load conditions and the on-peak demand loss of representative secondary distribution transformers multiplied by the number of secondary distribution transformers on the Company's distribution system. The estimated distribution transformer losses were 34 MW. The total secondary distribution demand losses, including distribution transformers and distribution secondaries, were 39 MW (as reflected on Exhibit MFM-12).

[16] The formula used to calculate secondary line losses was $L = I^2 * R$. Where:

L = the average demand loss per secondary line for the average of the 12 CP;

I = the average current on the secondary line; and

R = the average resistance for the secondary line.

C. Development of Transmission and Distribution Energy Losses

Q112. PLEASE PROVIDE AN OVERVIEW OF HOW ETI DEVELOPED ITS ENERGY LOSS FACTORS.

A. Energy loss factors were developed from engineering studies of ETI's transmission and distribution systems. The Company first estimated demand loss in order to estimate energy loss; that is, demand loss was an input into the Company's energy loss calculation. Exhibit MFM-12 depicts the process used by ETI to estimate demand losses, and Exhibit MFM-13 diagrams the process used by ETI to estimate energy losses.

The estimation process for energy losses was bottom-up; that is, the energy losses were determined for the lowest voltage level on the system and then for each successively higher voltage level from the secondary distribution system to the bulk transmission system. The Company calculated energy loss factors for the analysis period April 1, 2012 through March 31, 2013. The energy loss analysis that I sponsor estimated energy losses for four voltage levels: (1) the secondary distribution system; (2) the primary distribution system; (3) the transmission system below 230 kV and above 69 kV (local transmission system); and (4) the transmission system 230 kV and above (bulk transmission system).

Q113. PLEASE DESCRIBE HOW THE COMPANY CALCULATES ENERGY LOSS FACTORS.

A. Distribution energy losses are calculated by the SCALE model developed by EPRI. The SCALE model utilizes known energy loss characteristics of electric systems and observed customer demand patterns to estimate energy losses for distribution transformers, distribution secondaries, distribution primaries (feeders and laterals), and substation transformers. Observed analysis period load characteristics from a representative sampling of ETI's distribution system are input into SCALE to determine distribution energy losses. Transmission energy losses are determined by performing transmission load-flow simulations using the PSS/E model.

After the energy losses are estimated for all voltage levels, loss ratios for each voltage level are determined as the ratio of input energy to the input energy less the energy loss calculated for each voltage level. The cumulative energy loss factor for a given voltage level is determined as the product of the loss ratio for each voltage level and the cumulative energy loss factor for the next lower voltage level.

Q114. WHAT WERE THE COMPANY'S ENERGY LOSSES DURING THE ANALYSIS PERIOD?

A. During the analysis period, the energy injected into ETI's electric system by ETI's net generation and net interchange was 21,288,833 MWh. The energy consumed by ETI's customers was 19,344,597 MWh for the same period. The estimated energy loss of the Company's transmission and distribution system for the analysis period (using engineering equations and models) was estimated to be 1,102,565 MWh.

Q115. HOW WERE ENERGY LOSSES DETERMINED FOR ETI'S DISTRIBUTION TRANSFORMERS AND SECONDARIES?

A. Energy loss for secondary distribution transformers was determined by multiplying the product of the number of secondary distribution transformers on the ETI system by the sum of the full-load energy loss and the no-load energy loss for representative secondary distribution transformers. The secondary distribution transformer energy loss under both loading conditions was estimated from manufacturer test data of energy loss of representative test transformers under prescribed conditions. The following system load characteristics were utilized to determine distribution transformer energy losses: the peak responsibility factor (0.90 for the analysis period), the load factor (0.42 for the analysis period), and the loss factor (0.22 for the analysis period). Energy losses estimated for secondary distribution transformers were 250,733 MWh during the analysis period.

For distribution secondaries, ETI utilized the SCALE model and observed load data for the analysis period from a representative sampling of its secondary distribution system to determine secondary losses. The following system load characteristics were utilized to determine secondary losses: the peak responsibility factor (0.85 for the analysis period), the service coincident factor (0.85 for the analysis period), and the loss factor (0.22 for the analysis period). During the analysis period, the energy loss estimated for ETI's distribution secondaries was 16,447 MWh. The total secondary distribution energy losses including distribution transformers and distribution secondaries were 267,180 MWh (as reflected on Exhibit MFM-13).

Q116. PLEASE DESCRIBE HOW ENERGY LOSSES OF PRIMARY DISTRIBUTION WERE DETERMINED.

A. The energy losses for feeders and the laterals were calculated using the SCALE model. Annual energy losses were determined by calculating the product of full-load demand loss, the loss factor (0.25), and the number of hours per year. Primary distribution energy losses were estimated to be 309,456 MWh for the analysis period (as reflected on Exhibit MFM-13).

Q117. HOW WERE SUBSTATION TRANSFORMER ENERGY LOSSES ANALYZED?

A. The SCALE model estimated substation losses. ETI analyzed only the energy losses of substation transformers. Additional losses, such as in the substation transformer cooling fans, the control equipment, the feeder bay equipment, the lightning arrestors, and the capacitor banks, were minimal and not considered. Energy losses were determined under no-load and full-load conditions from manufacturer test data for representative substation transformers. During the analysis period, energy losses for substation transformers were estimated at 164,242 MWh (as reflected on Exhibit MFM-13).

Q118. HOW WERE TRANSMISSION ENERGY LOSSES DETERMINED?

A. ETI utilized the PSS/E transmission network load-flow analysis to estimate energy losses in the bulk and local transmission systems. PSS/E calculated the power flows for each transmission line and auto-transformer in the interconnected transmission network. The energy losses were analyzed at each transmission voltage level. One scenario for each month of the analysis period was run to calculate transmission energy losses. The scenarios analyzed changes in area generation, loads, sales, purchases, and seasonal changes on both the generation and transmission systems of neighboring utilities. During the analysis period, the estimated energy losses for the bulk transmission system were 97,645 MWh, and the estimated energy losses at the local transmission system were 264,043 MWh (as reflected on Exhibit MFM-13).

D. Summary of Results

Q119. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A. Summarizing from Exhibits MFM-12 and MFM-13, and as further presented in Schedule O-6.3, the results of the analyses described above are listed in Table 9.

Table 9

Voltage Level	Cumulative Demand Loss Factor	Cumulative Energy Loss Factor
Transmission 230 kV and Above (Bulk Transmission System)	**1.003190**	**1.004608**
Transmission below 230 and above 69 kV (Local Transmission System)	**1.013438**	**1.019753**
Distribution Primary System	**1.068849**	**1.060855**
Distribution Secondary System	**1.088532**	**1.088718**

The loss factors cited in the table above were calculated with respect to the generation source.

Q120. ARE THE DEMAND AND ENERGY LOSS FACTORS PROPOSED BY ETI IN THIS DOCKET THE SAME AS THE LOSS FACTORS PROPOSED BY ETI IN DOCKET NOS. 37744 AND 39896?

A. No. The demand and energy loss factors vary slightly among these dockets. Table 10 summarizes the loss factors calculated in Docket Nos. 37744 and 39896. Also, the percentage changes from the factors proposed in this proceeding to the factors calculated and proposed in those dockets are summarized. The variances in the loss factors in Table 10 are the result of changes in generation patterns and load patterns from one analysis period to the next. For Docket No. 37744, the analysis period was January 1, 2008 through December 31, 2008, and for Docket No. 39896, it was January 1, 2010 through December 31, 2010.

Table 10

Voltage Classes	Docket No. 37744	Docket No. 39896	Proposed Factors in this Proceeding
Demand			
Bulk	1.003675	1.003696	1.003190
Local	1.017129	1.015907	1.013438
Primary	1.069755	1.073141	1.068849
Secondary	1.090548	1.092546	1.088532
% Changes From Proposed Factors			
Bulk	0.00%	-0.05%	
Local	-0.12%	-0.24%	
Primary	0.32%	-0.40%	
Secondary	0.18%	-0.37%	
Energy			
Bulk	1.005793	1.005774	1.004608
Local	1.025272	1.023010	1.019753
Primary	1.058685	1.060428	1.060855
Secondary	1.087199	1.088754	1.088718
% Changes From Proposed Factors			
Bulk	0.00%	-0.12%	
Local	-0.22%	-0.32%	
Primary	0.16%	0.04%	
Secondary	0.14%	0.00%	

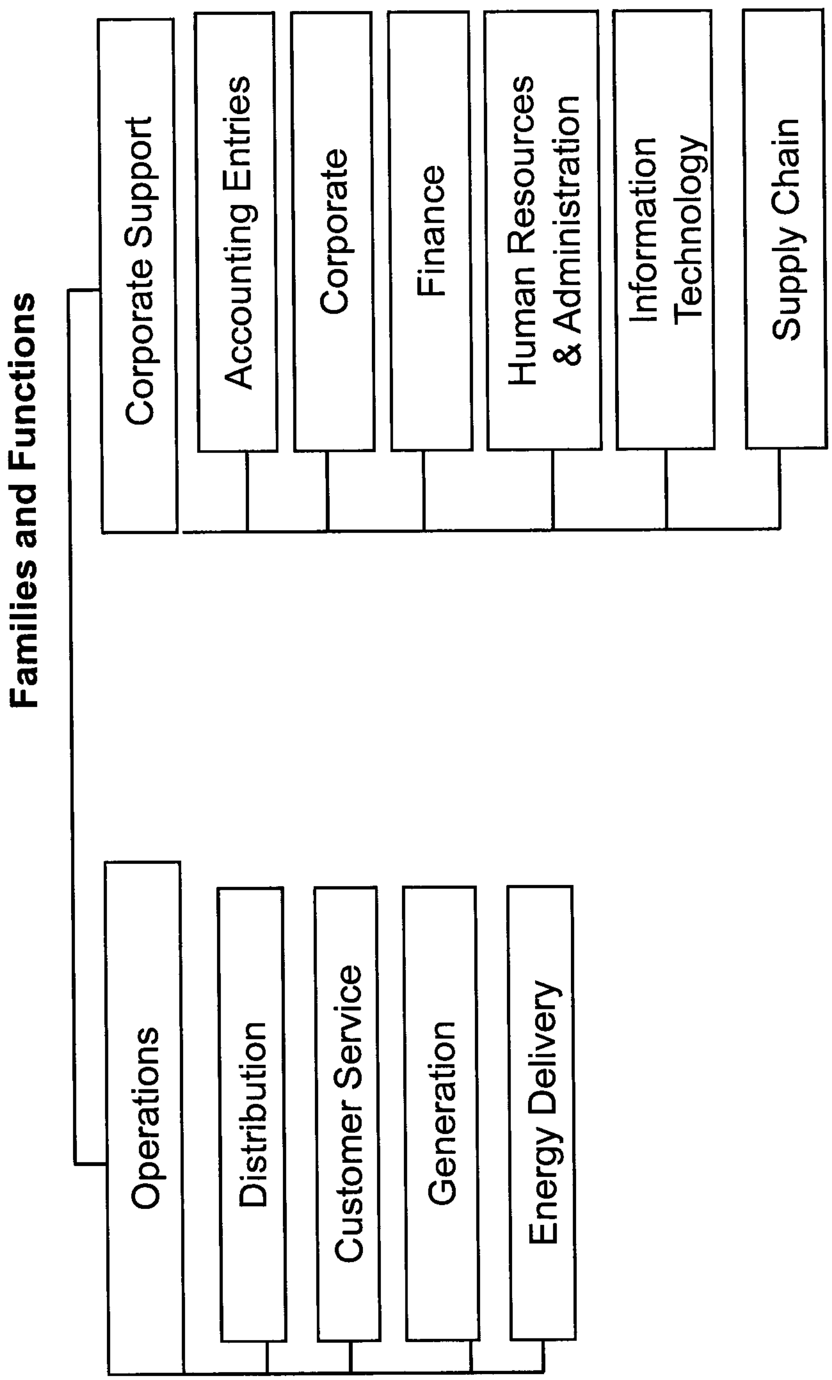
Q121. ARE THE RESULTS FROM THE LOSS ANALYSIS PRESENTED IN THIS TESTIMONY REASONABLE?

A. Yes. The demand and energy loss factors were calculated in a manner consistent with standard utility transmission planning practices. The projected cumulative demand and energy loss factors derived from the analysis are similar to previously calculated factors.

VI. CONCLUSION

Q122. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.


Families and Functions
Corporate Support
Accounting Entries
Corporate
Finance
Human Resources & Administration
Information Technology
Supply Chain
Operations
Distribution
Customer Service
Generation
Energy Delivery

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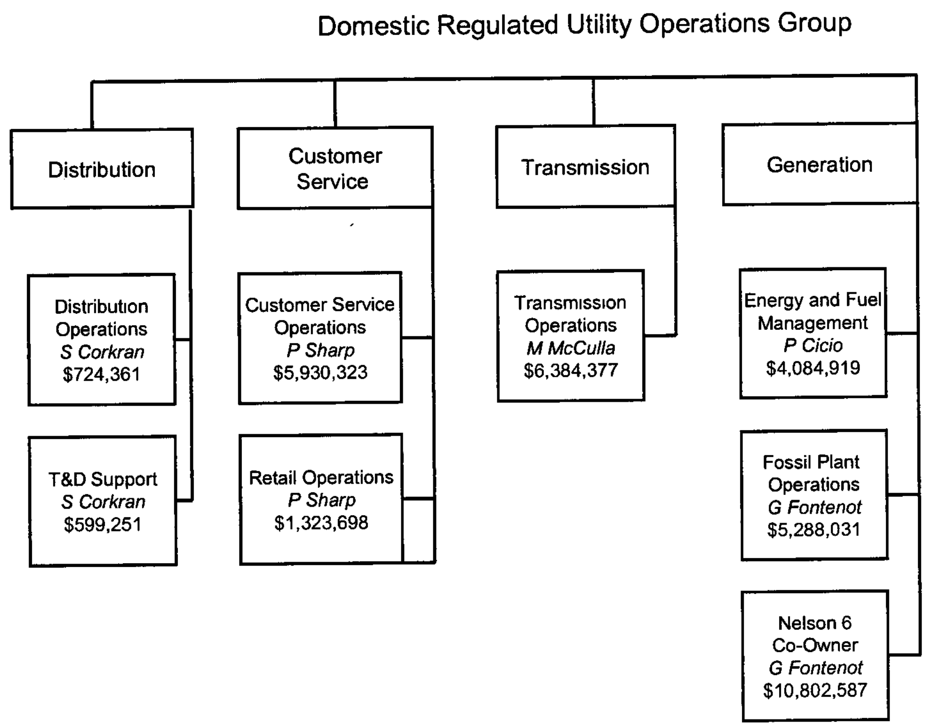
Operations Functions & Classes ($ Total ETI Adjusted)



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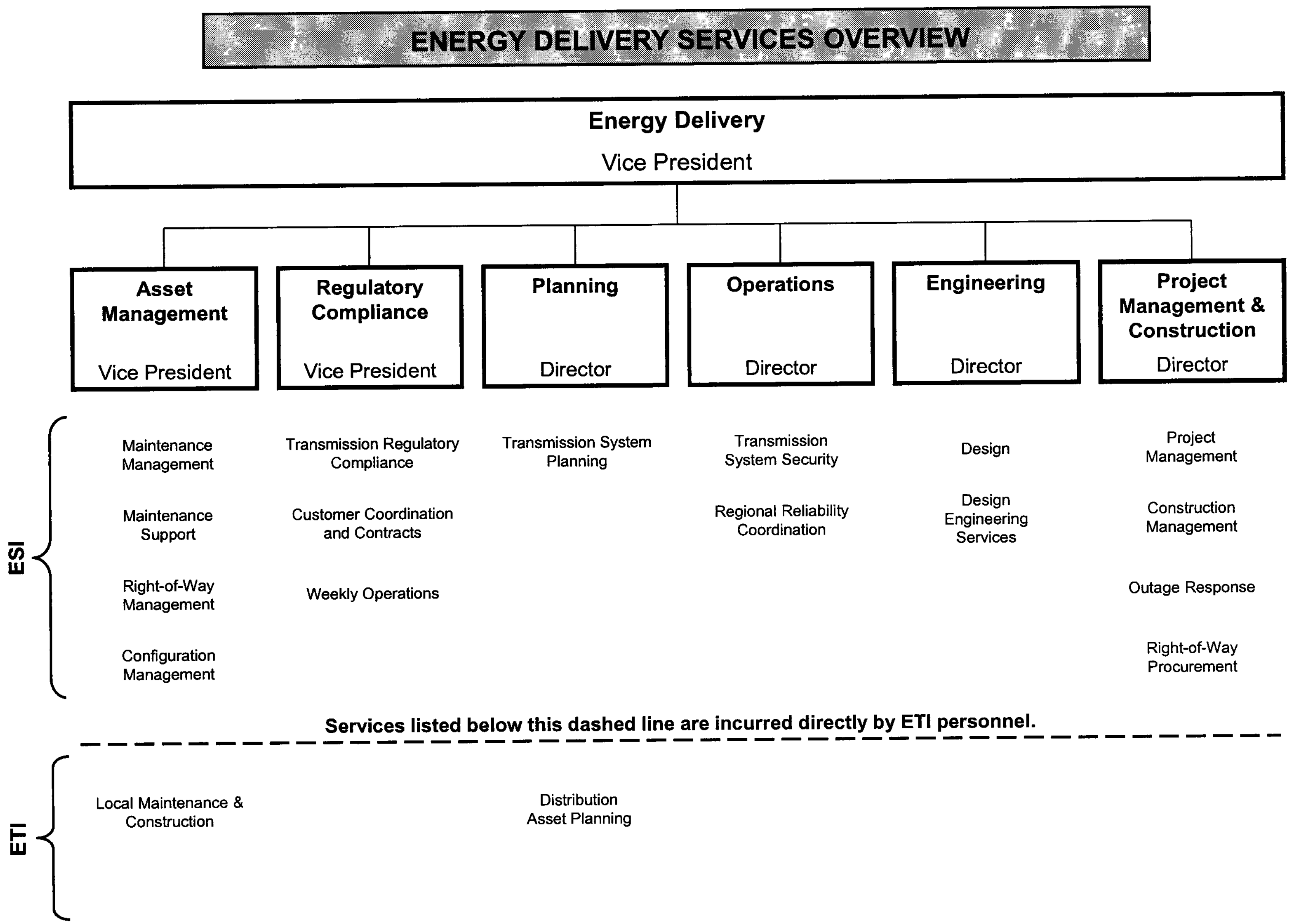
ENERGY DELIVERY SERVICES OVERVIEW
Energy Delivery
Vice President
Asset Management
Vice President
Regulatory Compliance
Vice President
Planning
Director
Operations
Director
Engineering
Director
Project Management & Construction
Director
ESI
Maintenance Management
Maintenance Support
Right-of-Way Management
Configuration Management
Transmission Regulatory Compliance
Customer Coordination and Contracts
Weekly Operations
Transmission System Planning
Transmission System Security
Regional Reliability Coordination
Design
Design Engineering Services
Project Management
Construction Management
Outage Response
Right-of-Way Procurement
Services listed below this dashed line are incurred directly by ETI personnel.
ETI
Local Maintenance & Construction
Distribution Asset Planning

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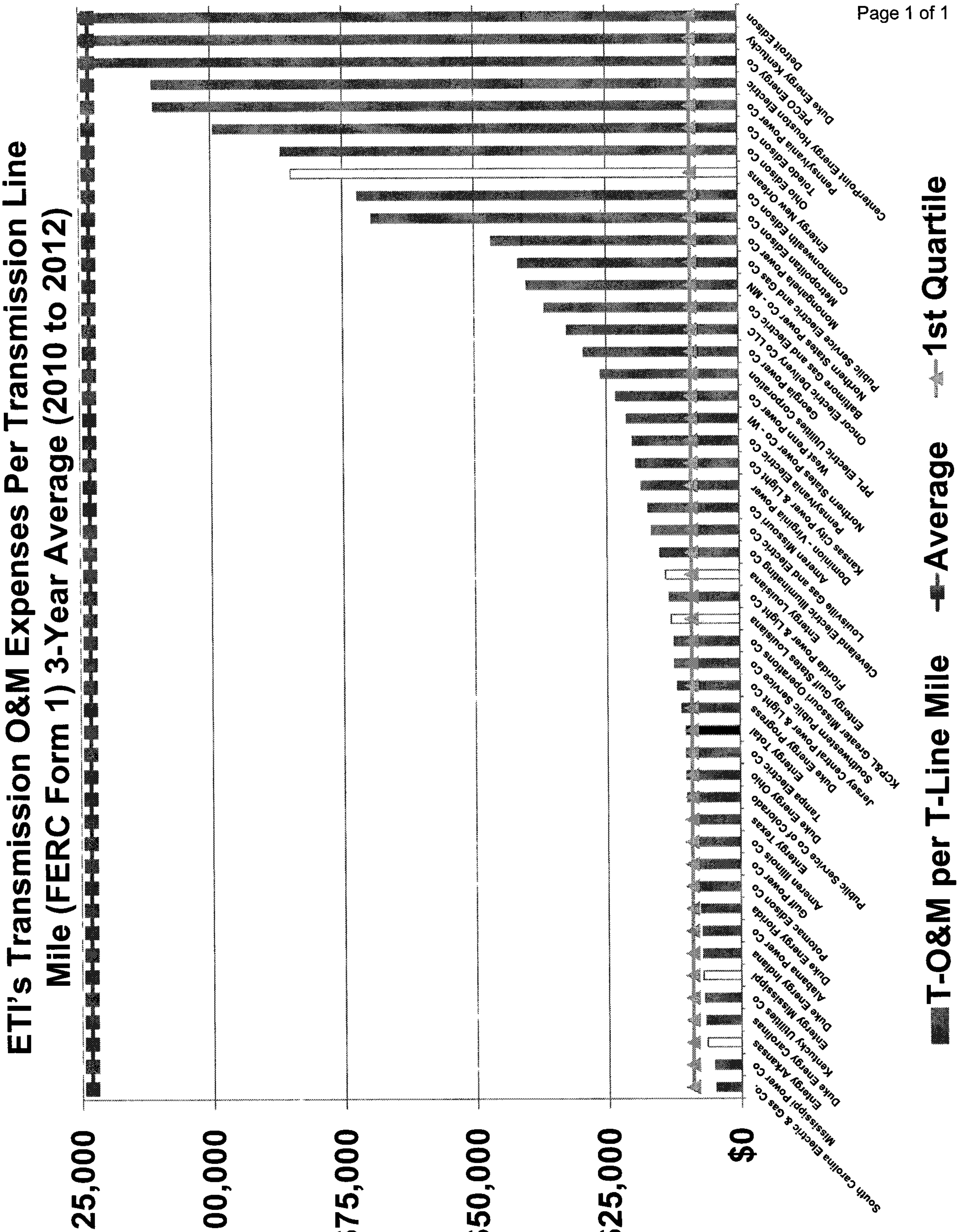
List of Utilities Considered for Entergy's Benchmarking Analysis

1. Alabama Power Company
2. Ameren Illinois
3. Ameren Missouri
4. Baltimore Gas & Electric Company
5. CenterPoint Energy Houston Electric, L.L.C.
6. Cleveland Electric Illuminating Company (The)
7. Commonwealth Edison Company
8. Detroit Edison Company (The)
9. Duke Energy Carolinas
10. Duke Energy Indiana
11. Duke Energy Kentucky
12. Duke Energy Ohio
13. Entergy Arkansas, Inc.
14. Entergy Gulf States Louisiana, L.L.C.
15. Entergy Louisiana, LLC
16. Entergy Mississippi, Inc.
17. Entergy New Orleans, Inc.
18. Entergy Texas, Inc.
19. Florida Power & Light Company
20. Georgia Power Company
21. Gulf Power Company
22. Jersey Central Power & Light Company
23. Kansas City Power & Light Company
24. KCP&L Greater Missouri Operations Company
25. Kentucky Utilities Company
26. Louisville Gas & Electric Company
27. Metropolitan Edison Company
28. Mississippi Power Company
29. Monogahela Power Company

30. Northern States Power Company (Minnesota)
31. Northern States Power Company (Wisconsin)
32. Ohio Edison Company
33. Oncor Electric Delivery
34. PECO Energy Company
35. Pennsylvania Electric Company
36. Pennsylvania Power Company
37. Potomac Edison Company (The)
38. PPL Electric Utilities Corporation
39. Progress Energy Carolinas
40. Progress Energy Florida
41. Public Service Company of Colorado
42. Public Service Electric & Gas Company
43. South Carolina Electric & Gas Company
44. Southwestern Public Service Company
45. Tampa Electric Company
46. Toledo Edison Company (The)
47. Virginia Electric & Power Company
48. West Penn Power Company


ETI's Transmission O&M Expenses Per Transmission Line Mile (FERC Form 1) 3-Year Average (2010 to 2012)
$125,000
$100,000
$75,000
$50,000
$25,000
$0
Detroit Edison
Duke Energy Kentucky
PECO Energy Co
CenterPoint Energy Houston Electric
Pennsylvania Power Co
Toledo Edison Co
Entergy New Orleans
Ohio Edison Co
Commonwealth Edison Co
Metropolitan Edison Co
Monongahela Power Co
Northern States Power Co - MN
Public Service Electric and Gas Co
Baltimore Gas and Electric Co
Oncor Electric Delivery Co LLC
Georgia Power Co
PPL Electric Utilities Corporation
West Penn Power Co
Northern States Power Co - WI
Pennsylvania Electric Co
Kansas City Power & Light Co
Dominion - Virginia Power
Ameren Missouri
Louisville Gas and Electric Co
Cleveland Electric Illuminating Co
Entergy Louisiana
Florida Power & Light Co
Entergy Gulf States Louisiana
KCP&L Greater Missouri Operations Co
Southwestern Public Service Co
Jersey Central Power & Light Co
Duke Energy Progress
Entergy Total
Tampa Electric Co
Duke Energy Ohio
Public Service Co of Colorado
Entergy Texas
Ameren Illinois Co
Gulf Power Co
Potomac Edison Co
Duke Energy Florida
Alabama Power Co
Duke Energy Indiana
Entergy Mississippi
Kentucky Utilities Co
Duke Energy Carolinas
Entergy Arkansas
Mississippi Power Co.
South Carolina Electric & Gas Co.
T-O&M per T-Line Mile
Average
1st Quartile

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ETI's Transmission O&M Expenses as a Percent of ETI's Total Transmission Assets (FERC Form 1) 3-Year Average (2010 to 2012)