As to Dr. Szerszen's legal conclusion that ETI is no longer authorized to recover Hurricane Katrina costs, ETI argues that PURA § 36.405 does not restrict or even apply to ETI's recovery of such costs. That section deals with securitization of system restoration costs, but ETI did not seek to securitize any Hurricane Katrina costs. Even so, argues ETI, if that section did apply, it does not restrict system restoration cost recovery solely to Docket No. 34800; that is, the "next base rate proceeding" following the hurricane. Instead, the final clause in PURA § 36.405(a) states in full that the Company is entitled to recover such costs "in its next base rate proceeding or through any other proceeding authorized by Subchapter C or D." The same point applies to the Hurricane Ike costs; while ETI did securitize the Hurricane Ike costs that it had incurred up to the date subject to that securitization, it continued to incur costs in this test year for that storm restoration (in this case, $441 billed to the Ike-related project code). The costs in these projects were incurred during the test year for this docket and could not have been recovered in an earlier docket. Moreover, ETI's filing in this docket was filed in accordance with PURA Subchapter C as a rate change proposed by a utility. As such, ETI contends that it is entitled to recover these costs.[817]

To the ALJs, the most important part of the argument is that ETI did not seek to avail itself of PURA § 36.405 with respect to Hurricane Katrina costs. It is difficult to understand how that section, which deals with securitization of hurricane costs, could block recovery when ETI did not seek to securitize those costs. Similarly, with respect to Hurricane Ike costs, the $441 challenged by Dr. Szerszen was not incurred until the Test Year and could not have been securitized. Ms. Tumminello provided testimony that the costs were reasonable and necessary, representing a part of ETI's normal utility operations. Accordingly, the ALJs recommend the Commission approve inclusion of the costs.

N. Regulatory Services Class

Dr. Szerszen challenged one project code that is primarily within the Regulatory Services Class of affiliate costs: Project F3PPE9981S (Integrated Energy Management for ESI) for a disallowance of $171,032.

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817 ETI Initial Brief at 188-189.

Dr. Szerszen testified that these costs were incurred for the implementation, coordination, and promotion of demand side and supply side management and energy efficiency programs. But, she stated, these costs should instead have been recovered through ETI's Energy Efficiency Cost Recovery Factor (EECRF) Rider and, as such, it is inappropriate to recover these costs through affiliate billings in base rates.[818]

ETI witness May testified that recovery of these costs through base rates rather than through the EECRF Rider is appropriate because these activities are not subject to an active ETI energy efficiency program. These activities are more in the nature of general research and development activities that help drive the Company's strategy on these topics, such as the timing of implementing related programs. In the meantime, until these activities result in an actual program proposal, these are legitimate known and measurable costs that the Company has incurred and should then be recovered from retail customers.[819] At the hearing, Mr. May further explained that the costs in this project code are labor costs that are "not really consistent" with the energy efficiency rule, but instead involve "primarily costs of investigating" potential future activities (such as smart meters and electric vehicle chargers) that are generally not consistent with the energy efficiency rider.[820] ETI witness Considine also addresses this issue from a regulatory accounting perspective. He testified: "Because these are not costs that must be, or are currently being recovered through the EECRF, they are not double recovered and should be included in the Company's cost of service."[821] According to ETI, the costs in this project code, therefore, are not costs that should or can be recovered through ETI's EECRF Rider.

This is a close call. The Commission's Energy Efficiency Rule places limits on the amount of research and development costs a utility may recover,[822] which supports the argument that the costs should be included in the EECRF. Further, it appears to the ALJs that research and development costs, by their very nature, do not relate to an active program, which negates many of

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818 OPC Ex. 1 (Szerszen Direct) at 69-70.

819 ETI Ex. 57 (May Rebuttal) at 30-31.

820 Tr. at 1929-1930 and 1934-1935.

821 ETI Ex. 46 (Considine Rebuttal) at 36.

822 P.U.C. SUBST. R. 25.181(i).

the arguments advanced by ETI witnesses May and Considine. In the end, the ALJs believe that these costs should be included in the EECRF. Accordingly, the ALJs recommend the Commission disallow costs in the amount of $171,032 relating to Project F3PPE9981S.

O. Retail Operations Class

Dr. Szerszen challenged three project codes that are primarily within ETI's Retail Operations Class of affiliate costs: (1) F5PPICCIMG (ICC – "Image" Message) for a disallowance of $3,912; (2) F3PPR56640 (Wholesale - EGS-TX) for a disallowance of $229,938; and (3) F3PPR56920 (Wholesale - All Jurisdictions) for a disallowance of $333.

1. Project F5PPICCIMG (ICC – "Image" Message)

Project Code F5PPICCIMG (ICC-"Image" Message) is one of the project codes that Dr. Szerszen testified should be disallowed because ETI is a monopoly and Texas ratepayers should not have to pay for corporate image costs.[823]

Ms. Tumminello testified that the costs are for advertising activities that are of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry, including advertisement which inform the public concerning matters affecting the Company's operations, such as, the costs of providing service, the Company's efforts to improve the quality of service, the Company's efforts to improve and protect the environment. According to FERC, such costs are properly includable in FERC Account 930.1 and are recoverable. According to Ms. Tumminello, as contemplated by FERC, the fact that ETI is a monopoly has no bearing on the recoverability of these costs.[824]

OPC provided little support for its claim that costs covered by these project codes should not be recoverable, essentially limiting the basis to the contention that ETI is a monopoly and ratepayers should not be charged with such costs. ETI did provide the testimony of Ms. Tumminello, which confirms that the costs are properly includable in FERC Account 930.1 and are, therefore,

[823] OPC Ex. 1 (Szerszen Direct) at 66.

[824] ETI Ex. 69 (Tumminello Rebuttal) at SBT-R-2 at 4-6.

recoverable. In the end, the weight of the evidence is in ETI's favor. The ALJs recommend the Commission reject OPC's contention that costs covered by these project codes are not recoverable.

2. Projects F3PPR56640 (Wholesale - EGS-TX) and F3PPR56920 (Wholesale - All Jurisdictions)

As to Projects F3PPR56640 and F3PPR56920, Dr. Szerszen stated that these costs are associated with assisting ETI's wholesale customers in evaluating alternative energy supply and demand options and that ETI's retail customers should not be charged for expenses associated with ETI's wholesale customers.[825]

ETI witness Stokes noted that ETI has allocated costs to its single large wholesale customer through its jurisdictional allocation in this rate case and, therefore, to disallow the costs in these two project codes would essentially result in a double disallowance of those costs. She also explained that the costs were properly allocable to ETI (keeping in mind that ETI then allocated costs to this customer) as reasonable and necessary due to the need to have staff on hand to handle contract negotiations and the like with this large wholesale customer.[826]

The ALJs are persuaded by ETI's argument that disallowing the costs associated with Projects F3PPR56640 and F3PPR56920, which are already allocated to ETI's single large wholesale customer through its jurisdictional allocation, would constitute a double disallowance. Accordingly, the ALJs recommend the Commission reject OPC's challenge to these costs.

P. Supply Chain Class

Dr. Szerszen challenged two project codes that are primarily within the Supply Chain Class: (1) F3PPH54075 (Business Development - TX) for a disallowance of $1,888; and (2) F5PCZSDEPT (Supervision & Support - Supply) for a disallowance of $146. Dr. Szerszen claimed the costs

[825] OPC Ex. 1 (Szerszen Direct) at 73.

[826] ETI Ex. 66 (Stokes Rebuttal) at 6-9.

associated with these project codes should be disallowed because ETI is a monopoly and Texas ratepayers should not have to pay for corporate image costs.[827]

Ms. Tumminello testified that the costs are for advertising activities that are of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry, including advertisement which inform the public concerning matters affecting the Company's operations, such as, the costs of providing service, the Company's efforts to improve the quality of service, the Company's efforts to improve and protect the environment, etc. According to FERC, such costs are properly includable in FERC Account 930.1 and are recoverable. According to Ms. Tumminello, as contemplated by FERC, the fact that ETI is a monopoly has no bearing on the recoverability of these costs.[828]

OPC provided little support for its claim that costs covered by these project codes should not be recoverable, essentially limiting the basis to the contention that ETI is a monopoly. ETI did provide the testimony of Ms. Tumminello, which confirms that the costs are properly includable in FERC Account 930.1 and are, therefore, recoverable. The ALJs go with the weight of the evidence, which is in ETI's favor. The ALJs recommend the Commission reject OPC's contention that costs covered by these project codes are not recoverable.

Q. Transmission and Distribution Support Class

Dr. Szerszen challenged three project codes that are included within the Company's Transmission and Distribution Support Class of affiliate costs: (1) F3PCT53130 (Operations Manager, Claims Management) for a disallowance of $42,287.50; (2) F3PCTDAMAG (Damage Claims Of Entergy Property) for a disallowance of $5,555; and (3) F3PCTPUBLC (Public Claims) for a disallowance of $3,968. Dr. Szerszen's rationale for disallowing 50 percent of the costs in each of these codes is the same. She believes that ETI's property damage and workers compensation claims should be direct billed instead of allocated through a customer count-based allocator;

[827] OPC Ex. 1 (Szerszen Direct) at 66.

[828] ETI Ex. 69 (Tumminello Rebuttal) at SBT-R-2 at 4-6.

managerial and supervisory costs should be allocated to the jurisdictions based on the jurisdictional direct charges; and the Company has not met its burden of proof as to these charges.[829]

Ms. Tumminello addressed Project F3PCT53130, stating that workers' compensation claims are tracked by jurisdiction as Dr. Szerszen suggested, and are the basis for billing method COMCLAIM. Project F3PCTWCOMP is used to capture the costs of workers' compensation claims, and bills to both regulated and non-regulated affiliates. Project F3PCT53130 captures costs that are primarily for the oversight of the Entergy Companies' Claims Management organization as it relates to property damage and liability. These services benefit only the companies that serve retail electric and gas customers. Since only the regulated utility operating companies (and not the non-regulated companies) serve retail customers, it is appropriate to bill these costs to the regulated companies based on their pro-rata share of total customers.[830]

Projects F3PCTDAMAG and F3PCTPUBLC are addressed by ETI witness Corkran. With respect to Project F3PCTDAMAG, Mr. Corkran stated that the costs associated with this project are associated with the Public Claims employees in the Claims Management Organization. Those employees pursue the recovery of claims allowed by law when the public inflicts damage to Company property. The costs of this service are allocated among all of Entergy's Operating Companies through billing method CUSTEGOP, which allocates costs based on the number of customers in each Operating Company. Dr. Szerszen claimed that the affiliate costs associated with pursuing those claims should be directly charged to each Entergy Operating Company based on the extent to which each claim pertains to the Operating Company instead of generally allocating the costs to all utility customers. Mr. Corkran testified that the allocation methodology is appropriate because the Public Claims employees provide knowledgeable, centralized, and consistent pursuit of damage claims. The actual monies recovered for damage to ETI's property are returned to ETI ratepayers as credits against the cost of repairing those damaged facilities, *i.e.*, the recoveries are not allocated pursuant to CUSTEGOP. Only the Public Claims employees' time and overheads are allocated pursuant to CUSTEGOP, which is reasonable and appropriate because the overall time

[829] OPC Exhibit No. 1 (Szerszen Direct) at 79-80.

[830] ETI Ex. 69 (Tumminello Rebuttal) at SBT-R-2 at 10.

spent by Public Claims employees in pursuing the recovery of claims is driven by the number of gas and electric customers in each Operating Company.[831]

With respect to Project F3PCTPUBLC, Mr. Corkran stated that the costs associated with this project are related to Public and Auto Liability employees in the Claims Management Organization. These employees pursue the resolution and settlement of damage claims made against the Operating Companies in a timely and fair manner through denials, negotiations, and payments. Such claims include allegations of damaged appliances due to voltage fluctuation, food loss due to power outages, and damage caused by Company vehicles (*e.g.*, mailboxes, fence posts, and automobiles). This is an important process that ensures that only warranted and justifiable claims are paid. The CUSTEGOP billing method is appropriate because the Public and Auto Liability employees provide knowledgeable, centralized, and consistent resolution of damage claims. The actual payments associated with ETI public damage claims are charged to ETI through the use of other project codes. Only the Public and Auto Liability employees' time and overheads are allocated pursuant to CUSTEGOP, which is reasonable and appropriate because the overall time spent by Public and Auto Liability employees in processing claims is driven by the number of gas and electric customers in each Operating Company.[832]

The explanations that ETI provides for the charges captured by these project codes and the method of allocation employed makes sense to the ALJs. In a large organization, it is necessary to have a group of people to process claims efficiently so that economies of scale can be realized; that is what ETI is doing with these project codes. These costs benefit all companies within the Entergy umbrella (or within the regulated entities portion as noted), so the allocation methodology employed is appropriate. The ALJs recommend the Commission reject OPC's challenge to the recovery of these costs.

[831] ETI Ex. 48 (Corkran Rebuttal) at 13-15.

[832] *Id.*

R. Tax Services Class

Dr. Szerszen proposed a 25 percent ($221,007) disallowance of costs billed to ETI from a single project code in this Tax Services Class: Project Code F3PCF10445 (Entergy Consolidated Tax Services). The costs in this project were incurred in the preparation, research, and other costs associated with Entergy's consolidated tax return. Dr. Szerszen testified that an assets-based allocator is not appropriate for these costs and that the costs in the project should instead be directly billed to each affiliate based on the time spent on preparing that affiliate's income and expense data.[833]

Company witness Galbraith, who sponsors ETI's Tax Services Class, stated that Dr. Szerszen apparently believes that all costs associated with the preparation of Entergy's consolidated tax return are captured by this project code and are allocated, when they should be direct-billed. Most of the costs associated with preparation of Entergy's consolidated tax return, according to Ms. Galbraith, are assigned to other project codes and are direct billed. Ms. Galbraith then explained that: (1) 56 percent of the time that Tax Services spent on the Entergy consolidated tax return were direct billed through other project codes to the affiliates; (2) the project code also captures costs for tax research (both federal and state and local), monthly closing activities not specific to one legal entity, tax training that is not jurisdiction specific, compliance with file retention policy, and administration staff time; and (3) why the assets-based allocator is the best method for allocating these departmental costs. According to Ms. Galbraith, the costs captured by this code are not susceptible to direct billing.[834]

The ALJs find that Dr. Szerszen did fail to consider that most of the costs of preparing Entergy's tax return are direct billed and that the costs covered by this project code are not susceptible to such a billing, which is why they are allocated. The ALJs, therefore, recommend the Commission reject OPC's challenge to ETI's allocation of these costs.

[833] OPC Ex. 1 (Szerszen Direct) at 63.

[834] ETI Ex. 26 (Galbraith Direct) at 10-12.

S. Transmission Operations Class

Dr. Szerszen challenged three project codes that are primarily within the Transmission Operations Class: (1) F3PPTDHY19 (Dept. of Justice Investigations) for a disallowance of $765; (2) F3PPTREORG (Transmission Re-Organization) for a disallowance of $3,661; and (3) F3PPF30211 (ESI Transmission Bldg (Reclassification)) for a disallowance of $229,991.[835]

Dr. Szerszen addressed Project F3PPTREORG (Transmission-Reorganization) and testified that costs covered by this project were incurred in 2009 and 2010 and, therefore, are not recurring.[836] Ms. Tumminello responds that, while these particular costs do not recur every year, they are representative of normal recurring utility operations and do recur as necessary and, as such, they should not be disallowed.[837]

Dr. Szerszen testified that Project F3PPF30211 (ESI Transmission Bldg.) captures interest costs after the ESI transmission building was placed in service. She contends that the costs are reclassified pre-Test Year payments and post-Test Year interest costs that are not known and measureable.[838] Ms. Tumminello testified that Dr. Szerszen has misconstrued accounting entries. She explains that these charges capture 12 months of interest payments and the annual bond fee incurred only during the Test Year.[839]

The ALJs find that the costs associated with Project F3PPTREORG are representative of costs that recur every year and should not be disallowed. It appears to the ALJs that Dr. Szerszen did misconstrue accounting entries in preparing her analysis of Project F3PPF30211and that the charges in that project capture fees paid during the Test Year. Accordingly, the ALJs recommend that OPC's proposed disallowance be denied.

[835] Project F3PPTDHY19 (Dept. of Justice Investigations) was discussed in Section VIII.L. (Legal Services Class) and will not be repeated here

[836] OPC Ex. 1 (Szerszen Direct) at 54, Schedule CAS-8.

[837] ETI Ex. 69 (Tumminello Rebuttal) at SBT-R-2 at 1.

[838] OPC Ex. 1 (Szerszen Direct) at 71.

[839] ETI Ex. 69 (Tumminello Rebuttal) at 15. See also Ex. SBT-R-5.

T. Treasury Operations Class

Dr. Szerszen challenged three project codes that are primarily within the Treasury Operations Class: (1) F5PCZZI07P (Directors & Officers (EIM)) for a disallowance of $14,483; (2) F3PCF25300 (Daily Cash Mgt Activities) for a disallowance of $7,286; and (3) F3PCF26022 (Financing & Short Term Funding) for a disallowance of $96,700.

With respect to Project F5PCZZ107P (Directors & Officers (EIM)), Dr. Szerszen testified that the directors and officers liability insurance subject to this project code is primarily aimed at benefiting shareholders, rather than ratepayers and, because ETI does not manage ESI's operations, it should not be responsible for indemnifying against shareholder lawsuits.[840]

ETI witness McNeal stated that ESI provides essential administrative and operational services to ETI on a daily basis. To do this, it must employ (and retain) qualified officers and directors. These individuals must be assured that they can make reasoned decisions without fear of personal liability and the manner to provide them this assurance is to purchase director's and officer's liability insurance. Because ETI benefits from the services provided by the officers and directors, ETI argues, it is appropriate to allocate a portion of the cost of the director's and officer's liability insurance to ETI.[841]

Dr. Szerszen addressed Projects F3PCF25300 (Daily Cash Mgt Activities) and F3PCF26022 (Financing & Short Term Funding), contending that these projects are duplicative of ETI-specific financing and cash management activities; that these costs should be borne by Entergy shareholders; and that the bank accounts-based and level of service-based allocators applicable to this projects are not appropriate.[842]

ETI responds that Project F3PCF25300 captures costs for activities performed by the Cash Management Department for work associated with maintaining bank relationships, bank fee analysis,

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[840] OPC Ex. 1 (Szerszen Direct) at 59.

[841] ETI Ex. 61 (McNeal Rebuttal) at 7-8.

[842] OPC Ex. 1 (Szerszen Direct) at 74-75, Ex. CAS-15.

administrative of bank systems and controls, and all other banking and cash management activities that are general in nature. These are not specific to any one company, but are applicable to all of the companies within the umbrella of the Entergy corporate family. There are Company-specific activities that are charged directly to ETI under different project codes, and this constitutes the majority of financing and cash management activities during the Test Year. For Project F3PCF25300, the costs are driven by cash management products and services delivered to all the Entergy companies. Because the number of transactions executed on behalf of each Entergy company is directly related to the number of bank accounts by company irrespective of account size, billing method BNKACCTA, which allocates costs based on the number of open bank accounts is, according to ETI, the appropriate method to allocate the costs of these services.[843]

With respect to Project F3PCF26022, ETI explains that the project code captures costs for managing Entergy companies' liability portfolios comprised of Entergy company securities, bank lines, and project financings. The work is performed for the benefit of all companies under the Entergy corporate umbrella, not just ETI and is not duplicative of services performed for ETI. When work is performed by ESI personnel that relates specifically to ETI, then ETI is charged directly under a different project code. The services include analyzing and supporting general capital structure policy, developing and analyzing general financial policies, investigating and evaluating financing options generally that might prove beneficial for any or all Entergy companies, including ETI, and facilitating ongoing administration related to all Entergy Operating Company financings. Accordingly, ETI argues that it is appropriate to allocate a share of those costs to ETI. The costs of this project are driven by the level of service needed to complete the project or activity. Allocator LVSVCAL allocates costs based upon the overall service level of ESI. This allocation is appropriate because ESI is providing the service and no one Operating Company alone benefits from the services provided under this project code.[844]

OPC appears to have taken too narrow a view with respect to these project codes. First, it appears that where services are performed solely for ETI, they are charged to ETI through specific

[843] ETI Ex. 61 (McNeal Rebuttal) at 3-6; Tr. at 546.

[844] ETI Ex. 61 (McNeal Rebuttal) at 2-3; Tr. at 547-548.

project codes. The project codes that OPC challenges are for company-wide services that are partially allocated to ETI. It is logical to assume that a certain level of services can be performed more efficiently at a company-wide level and that Texas ratepayers will benefit by paying only the allocated portion of those costs, as is done in these cases. The allocators chosen by ETI appear to reasonably reflect the cost-causation. Therefore, the ALJs recommend that OPC's challenge be rejected.

U. Utility and Executive Management Class

OPC challenges five project codes that are primarily within the Utility & Executive Management Class: (1) F3PPCCS010 (Climate Consulting Services) for a disallowance of $19,821; (2) F3PCCPM001 (Corporate Performance Management) for a disallowance of $173,867; (3) F3PCC31255 (Operations-Office of the CEO) for a disallowance of $372,919; (4) F3PPCAO001 (Chief Administrative Officer) for a disallowance of $177,156; and (5) F3PPCOO001 (Chief Operating Officer) for a disallowance of $74,485.

As to the first, Project F3PPCCS010 (Climate Counseling Services), Dr. Szerszen testified that these costs are incurred for the development of company-wide environmental policies, procedures, and programs; that expenses are improperly allocated to the subsidiaries based on each company's fossil operating capacity; and, as a result, the non-regulated affiliates are not allocated any environmental initiative expenses. She therefore recommended that 50 percent of this project's costs be disallowed.[845]

ETI witness Stokes addressed Dr. Szerszen's challenge to this project. Ms. Stokes explained that although nuclear-related environmental projects are being pursued, they are not being pursued using the project code referenced by Dr. Szerszen in her challenge. The costs for non-regulated affiliates are charged to projects not included in ETI's affiliate costs in this case. Non-regulated

[845] OPC Ex. 1 (Szerszen Direct) at 62.

affiliates use project codes specific to their businesses to maintain a separation of costs between regulated and non-regulated Entergy subsidiaries.[846]

For the remaining four project codes in this class, Dr. Szerszen stated that executive management is primarily concerned with overall corporate functions rather than issues for any one specific subsidiary, and there is no relationship between an assets-based allocator and executive management.[847]

ETI responds to these arguments by stating that the functions covered by these project codes relate to the oversight of all system operations and the stewardship of corporate assets and that because ETI is part of a corporate group, the allocated charges associated with these services are relevant to ETI as part of that group of companies. Furthermore, ETI argues, the asset-based allocator is appropriate because it reflects the cause of the costs incurred, in that, services provided relate to the stewardship of all the corporation's assets.[848]

A corporation cannot function without executives, who are charged with the responsibility of overseeing, among other things, the assets of the corporation. This is an important function that Dr. Szerszen did not acknowledge in her testimony. The utility and executive management class costs that she challenges are reasonable and necessary costs that are allocated to ETI based on a logical allocator – the assets the executives manage. The ALJs recommend that OPC's challenge be rejected.

IX. JURISDICTIONAL COST ALLOCATION [Germane to Preliminary Order Issue No. 13]

Jurisdictional cost allocation involves the proper method for allocating production costs between ETI's Texas retail customers and its wholesale customers, which are subject to FERC jurisdiction. During the Test Year, ETI provided electric service to retail customers and to three wholesale customers—including ETEC—under service agreements and rates approved by FERC.

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[846] ETI Ex. 66 (Stokes Rebuttal) at 5.

[847] OPC Ex. 1 (Szerszen Direct) at 56, 60.

ETEC is a partial requirements customer, and it will be ETI's only wholesale customer during the Rate Year. ETI estimated its cost of serving wholesale customers in a jurisdictional separation study that split ETI's cost of service between retail and the wholesale jurisdictions.[849]

To calculate the wholesale cost allocation factor, ETI proposed the use of 150 MW for the wholesale load. This results in a retail production demand allocation factor of 95.3838 percent. The 150-MW load represents the contractual minimum amount of capacity for which ETEC is obligated to pay under its partial requirements agreement. No party contests this aspect of ETI's proposed allocation of costs between retail and wholesale customers.[850]

However, Cities contest the type of allocation methodology used to assign demand-related (fixed) production costs to each jurisdiction. In this proceeding, ETI used the A&E 4CP allocation method. Although this is the same methodology ETI used in this proceeding's class cost-of-service study (to assign demand-related production costs to each retail customer class), ETI used a different methodology – 12 Coincident Peak (12CP) – in its last rate case to assign costs between jurisdictions.[851]

A. A&E 4CP

Kroger witness Kevin C. Higgins explained the A&E 4CP method:

> [T]he Average and Excess Demand method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The cost of capacity above average demand is then allocated in proportion to each class's <u>excess</u> demand, where excess demand is measured as the *difference* between each class's individual peak demand and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above

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[848] ETI Ex. 4 (Domino Direct) at 18-38; ETI Ex. 69 (Tumminello Rebuttal) at 9-11.

[849] Cities Ex. 4 (Goins Direct) at 4.

[850] ETI Ex. 7 (May Direct) at 23-24. Ms. Talkington used the 150 MW number sponsored by Mr. May, and the associated energy use, to calculate the jurisdictional allocation factor. ETI Ex. 22 (Talkington Direct) at 11-12.

[851] Cities Ex. 4 (Goins Direct) at 10.

> average demand is assigned to the users who create the need for the additional capacity. . . . the A&E/4CP variant . . . uses 4 CP to measure excess demand, whereas the conventional version uses class non-coincident peak . . . .[852]

ETI witness Myra L. Talkington also explained that the A&E 4CP method, noting that ETI's coincident peak demand is measured for the months of June through September. Ms. Talkington recommends the A&E 4CP allocation because it "reasonably reflects the mix of the Company's customers and their respective electrical load characteristics and the relative cost incurred to serve such loads."[853] She also believes this allocation methodology provides a reasonable balance between the contribution to the system peak and energy requirements.[854]

As noted above, ETI's use of A&E 4CP is a change from the 12CP methodology it used when it operated within two states. Ms. Talkington testified that 12CP was appropriate in the past because System Agreement costs were allocated between Entergy Operating Companies using 12CP. The Texas retail portion of the production costs were then allocated between the retail classes using the A&E 4CP methodology (as ETI is doing in this case). However, according to Ms. Talkington, now that ETI operates in only one state, no jurisdictional allocation among states is necessary; therefore, only one allocation methodology, *i.e.*, A&E 4CP, should be used to allocate production costs between the retail classes and the wholesale jurisdiction. Ms. Talkington testified that the A&E 4CP methodology factors in year-round demand through the average and excess function and also matches the allocator used to allocate costs within the retail class.[855]

Cities opposes the use of A&E 4CP and suggest a 12CP methodology is preferable. Commission Staff does not oppose ETI's use of A&E 4CP. No other party takes a position on this issue.

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[852] Kroger Ex. 2 (Higgins Cross Rebuttal) at 3 (footnotes deleted).

[853] ETI Ex. 23 (Talkington Direct) at 6; OPC Ex. 6 (Benedict Direct) at 17.

[854] ETI Ex. 23 (Talkington Direct) at 6.

[855] ETI Ex. 67 (Talkington Rebuttal) at 6-7.

B. 12CP

The12CP methodology allocates production capacity costs in proportion to each class's demands that occur on the date and time of ETI's system peak in each of the 12 months.[856] Cities believe it is more appropriate for ETI to allocate fixed production costs between the wholesale customers and Texas retail customers using 12CP. Cities witness Dennis W. Goins testified that the 12CP approach is consistent with the cost-of-service approach FERC typically uses to allocate demand-related production costs reflected in wholesale rate schedules, and it is consistent with the assignment of MSS-1 costs (as well as MSS-2 transmission costs) to ETI under the Entergy System Agreement. Dr. Goins reviewed ETI's Rate Year purchased power capacity costs month by month. He determined that ETI's heavy reliance on capacity purchases to serve retail and wholesale load, and the relative stability of those projected monthly purchased power capacity costs, suggest that the 12CP method should properly split ETI's demand-related production costs between the Texas retail and wholesale jurisdictions.[857]

Dr. Goins calculated Test Year 12CP allocation factors for the Texas retail and wholesale jurisdictions, and provided them to Cities witness Karl Nalepa for inclusion in his jurisdictional separation study. He determined the following:[858]

Jurisdiction	A&E 4CP	12CP
Texas Retail	95.3838%	94.6208%
Wholesale	4.6162%	5.7923%
Total	100%	100%

In making this calculation, Dr. Goins used a loss-adjusted 150 MW (ETEC's monthly billing MW) as a proxy for the 12 monthly CPs. In his view, the 150 MW is indicative of ETI's

[856] TIEC Ex. 3 (Pollock Cross Rebuttal) at 26.

[857] Cities Ex. 4 (Goins Direct) at 10-12.

[858] Cities Ex. 4 (Goins Direct) at 12.

capacity obligations to ETEC, and it reflects known and measurable changes compared to test-year wholesale CPs (which would include CPs for wholesale customers that ETI no longer serves).[859]

Cities point out that ETI previously allocated production costs to the wholesale jurisdiction on a 12CP basis. ETI first requested that the Commission change the 12CP method in Docket No. 37744.[860] According to Cities, ETI's request to change the 12CP methodology in Docket No. 37744 is significant because ETI's wholesale load consisted of Brazos Electric Cooperative, Inc. (Brazos) and ETEC. The Brazos contract assigned Brazos' share of ETI's production costs based upon a 12CP allocator. Thus, contends Cities, all costs that would have been over-allocated to retail customers would have been pocketed by ETI (if the 12CP allocator had changed). Cities argue that ETI's request to deviate from its approved 12CP allocator will result in retail customers subsidizing production costs. Dr. Goins calculated that the 12CP allocation factor for ETI's wholesale jurisdiction is approximately 5.38 percent versus 4.62 percent under the A&E 4CP method.[861] Cities conclude that retail customers will subsidize the difference between the two allocators, which is 0.76 percent. Because the allocation is applied to all production costs, including purchased power capacity costs, the 0.76 percent difference is significant, contend Cities.

According to ETI, Cities' arguments are based on a non-existent situation—the provision of service to Brazos—and should be rejected. The ALJs acknowledge that ETI is no longer serving Brazos. Dr. Goins noted such in his testimony. Rather, the basis for his recommendation was: (1) the 12CP approach is consistent with FERC's wholesale rate allocation; (2) the 12CP method is used to derive each Entergy Operating Company's load responsibility ratio and share of monthly MSS-1 and MSS-2 charges; and (3) ETI's purchased power capacity costs do not vary significantly month to month. Although Ms. Talkington understood that the A&E 4CP methodology is the same one used to allocate production costs between classes, TIEC witness Pollock noted that it is often not appropriate to use the same allocation method for both jurisdictional and class allocations. He noted that, in jurisdictional separation, allocations are between retail and wholesale entities, with wholesale

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859 Cities Ex. 4 (Goins Direct) at 10-12.

860 The parties in that docket stipulated the majority of issues in the case, including issues relating to jurisdictional allocation.

861 Cities Ex. 4 (Goins Direct) at 11-12.

subject to FERC regulation.[862] ETI did not fully explain why A&E 4CP is the best methodology for allocation production costs between the retail and wholesale jurisdictions. Dr. Goins' and Mr. Pollock's testimonies were ultimately more persuasive on this issue. Accordingly, the ALJs recommend the use of 12CP to allocate capacity-related production costs between the retail and wholesale jurisdictions.

X. CLASS COST ALLOCATION AND RATE DESIGN [Germane to Preliminary Order Issue No. 1]

ETI witness Talkington testified regarding the allocation methods for each of the major function/classification cost categories used in the Company's retail class cost-of-service study. Ms. Talkington also sponsors ETI's proposed rate design. Contested issues are set out below.

A. Renewable Energy Credit Rider [Germane to Preliminary Order Issue No. 19]

The Legislature has established a goal for the installation of an additional 5,000 MW of generating capacity from renewable energy technology. It also set out annual goals for electric utilities to meet on a cumulative basis in order to encourage the development of renewable energy generation in Texas. A utility may meet its annual goals by installing generation, by purchasing capacity based on renewable energy technology, or by purchasing sufficient renewable energy credits (RECs).[863]

1. ETI's Proposed Cost Recovery

Staff witness William B. Abbott explained that the Company currently recovers its REC costs through base rates. Each credit represents one megawatt-hour (MWh) of renewable energy that meets certain criteria set forth in P.U.C. SUBST. R. 25.173(e), and these credits can be traded among participants in the Texas market. ETI proposes to remove these costs from base rates and implement a REC Rider to recover its projected REC costs. After the initial rider is established, the REC Rider

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862 TIEC Ex. 3 (Pollock Cross Rebuttal) at 29. The ALJs acknowledge that Mr. Pollock does not contest ETI's use of the A&E 4CP jurisdictional allocation methodology—rather, his testimony was explaining why 12CP is not appropriate as an allocator among the different customer classes.

863 PURA §39.904(a) and (b).

would be reset annually to recover projected REC costs for the upcoming year, adjusted by any past over- or under-recovery and any revenue-related expenses.[864] With the introduction of the REC Rider, ETI would withdraw its current Renewable Portfolio Standard Calculation Opt-Out Credit Rider, which provides a credit to offset the base rate REC costs for certain customers who are exempt from paying REC costs. These customers would instead be exempt from charges under the proposed REC Rider.[865]

ETI suggests that a rider is necessary because the level of REC costs incurred from year to year is not known, and the cots are unknowable and very volatile. ETI witness Heather G. LeBlanc testified that certain customers can opt out, and a rider is the most efficient manner to administer such opt out.[866]

Initially, ETI based its rates for the proposed rider on the Company's Test Year renewable energy credit costs, which were incurred on a Texas retail basis for the 12 months ending June 30, 2011. ETI requested $623,303 and, after applying the revenue-related expense factor of 1.01307, proposed a revenue requirement of $631,450.[867] In rebuttal testimony, Ms. LeBlanc stated that the Company's proposal should be updated to reflect the most current data available. She stated that "events" since the Company's initial filing in November 2011 caused costs for the Company to increase.[868] She calculated an updated amount of $1,145,043, which, when the revenue-related expense factor is applied, results in an updated revenue requirement of $1,160,008.[869] She believes that the updated amounts further support the Company's position that REC costs are volatile.

2. Opposition to ETI's Proposal

Cities, OPC, State Agencies, and Commission Staff oppose ETI's proposed REC Rider.

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[864] *See* ETI Ex. 31 (LeBlanc Direct) at 26.

[865] Staff Ex. 7 (Abbott Direct) at 11-12.

[866] ETI Ex. 31 (LeBlanc Direct) at 25.

[867] *Id.* at 24. This amount is then divided by all non-transmission level kWh sales.

[868] ETI Ex. 55 (LeBlanc Rebuttal) at 10-11.

[869] *Id.* at 11. This amount is then divided by all non-transmission level kWh sales.

State Agencies argue that ETI's proposed REC Rider should be rejected because it deviates from the Commission's ratemaking policies and is inconsistent with PURA. State Agencies witness Kit Pevoto testified that the proposed rider is not appropriate because: (1) the rider is piecemeal ratemaking, which deviates from the Commission's traditional ratemaking policies and is inconsistent with PURA; (2) the reconciliation (true-up) process in the proposed tariff is not specifically provided for by PURA or PUC rule, or required to implement the REC process; (3) the redetermination of rates in the proposed annual filings would be based on projected or estimated costs, rather than historical test year costs; which is not in compliance with PURA or the Commission's rules; and (4) ETI has not justified the need to have a rate recovery for REC costs outside of the traditional PURA base rate recovery. Ms. Pevoto explained that the traditional test year cost of service ratemaking process, including regulatory lag, helps to match costs and revenues and to provide incentives that balance the utility's and its customers' interests. The proposed REC rider deviates from the traditional PURA rate-setting because it allows the Company to reset its rates automatically each year without going through a comprehensive rate proceeding. In her view, the rider would eliminate the regulatory lag incentive for ETI to prudently manage these costs because the rider allows for annual cost recovery adjustments. Ms. Pevoto observed that various provisions in PURA authorize riders for collection of other expenses, but no such provision exists for recovery of REC expenses, even though the Legislature mandated that utilities be responsible for a certain level of REC MWs. And she noted that if ETI's REC expenses increase due to increases in total REC MW requirements, ETI can request to include those increased costs in a future rate case.[870]

In reference to Ms. LeBlanc's rebuttal testimony that "events" caused ETI's REC costs to increase, State Agencies contend that ETI may have paid more for RECs during the Test Year because it contacted suppliers only after the REC requirement was mandated. ETI acknowledged that RECs were in the $1.10 to $1.25 range at the beginning of the year and then appreciated to over $2.00 and peaked out at $2.55 in the first quarter of 2012. Moreover, one of the largest REC suppliers unexpectedly withdrew its offers in March of 2011, which also led to price increases. March 31 is the end of the compliance period, and the deadline may increase the volume of

[870] State Agencies Ex. 2 (Pevoto Direct) at 6, 8-11.

purchases, which can add to price increases.[871] State Agencies note that ETI did not participate in the competitive REC market until February 2012 and bought its RECs near the peak price. State Agencies contend that only Test Year costs of $623,303 should be included in base rates.

Cities witness Karl Nalepa also opposed the REC Rider. He testified that the Commission should not permit ETI to single out REC costs from base rates because it presented no evidence that these costs should be treated differently than they are now. He added that RECs are not related to fuel so much as they are related to retail sales and plant output. In his opinion, the Test Year amount for REC of $633,985 should be included in base rates.[872] Cities witness James Z. Brazell also testified that ETI currently recovers a large portion of its revenues through non-fuel piecemeal riders. While he believes some riders are necessary and appropriate, ETI's general movement of cost recovery from base rates to riders (as evidenced in this proceeding) is inconsistent with PURA and the prohibition against piecemeal ratemaking.[873]

OPC also opposed ETI's proposed REC Rider on the basis that it constitutes piecemeal ratemaking. OPC witness Nathan A. Benedict noted that in Project No. 35628, the Commission rejected alternative mechanisms for the recovery of REC costs but reserved the right to consider the issue at a later date.[874] He stressed that, when rejecting alternative recovery mechanisms for REC costs, the Commission recognized that REC costs are variable, that the purchase of RECs is mandated by law, and that certain customers can opt out of the Renewable Portfolio Standard program. Thus, in Mr. Benedict's view, the Commission has already rejected the arguments advanced by ETI here. He added that ETI did not indicate a negative and substantial impact as a result of transmission customers opting out of the Renewable Portfolio Standard program, and ETI appears to be currently administering the program effectively without REC Rider. In short, Mr. Benedict concluded that costs related to renewable energy credits should be recovered through

[871] State Agencies Ex. 12, RFI.

[872] Cities Ex. 6 (Nalepa Direct) at 30-32. Mr. Nalepa's figure of $633,985 differs from that the figure of $623,303 found in ETI's testimony at ETI Ex. 31 (LeBlanc Direct) at 24 and State Ex. 9.

[873] Cities Ex. 1 (Brazell Direct) at 14-16.

[874] OPC Ex. 6 (Benedict Direct) at Ex. NAB-8, Project No. 35628, *Rulemaking Relating to Industrial Customer Opt-Out of Renewable Portfolio Standard*, Order at 6 (December 4, 2008).

base rates, and ETI's current opt-out rider should continue as the vehicle for ETI to handle transmission-level opt-outs.[875]

Commission Staff also opposes ETI's request, stating that it amounts to unauthorized piecemeal ratemaking that should be disallowed. In Staff's view, the existing opt-out rider should be maintained but updated to reflect the test year data used to set the ETI's base rates. Because ETI's proposed rider would include a true-up provision that would guarantee recovery of all of its REC costs, Staff witness Abbott testified that it would violate PURA § 36.051, which provides the utility a reasonable opportunity to earn a reasonable return on invested capital but does not guarantee full recovery of all costs. Mr. Abbott acknowledged that the Legislature has authorized the recovery of certain specific costs outside of base rates, but no such authorization exists for the recovery of REC costs.[876]

In addition, Mr. Abbott criticized the proposed REC rider because in the future it would allow *prospective* recovery of *estimated* REC costs. He believed that such an arrangement would eliminate any regulatory lag and thus eliminate any incentive for ETI to minimize the costs of purchasing the required RECs.[877] Mr. Abbott also pointed out that the proposed rider contains a single rate for all customer classes and includes a "revenue related expense factor," which increases the overall rider revenue requirement to, in part, account for projected uncollectable bills.[878] This would shift the costs of uncollectable bills from customer classes with greater bad debt onto customer classes with lower bad debt. Further, Mr. Abbott stated, the proposed true-up portion of the REC Rider would eliminate the need for a bad debt factor, as any actual under-collected amounts

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[875] OPC Ex. 6 (Benedict Direct) at 37-41. ETI currently has a Renewable Portfolio Standard Calculation Opt-Out Credit Rider to credit REC costs collected in base rates from transmission level customers who have opted out of the program.

[876] Staff Ex. 7 (Abbott Direct) at 12-13. Mr. Abbott cites to PURA §§ 36.203 (Fuel Cost Recovery), 36.205 (Purchased Power Cost Recovery), 36.209 (Transmission Cost Recovery), 36.210 (Distribution Cost Recovery), 39.107(h) (Advanced Meter Deployment Surcharge), 39.461 (Hurricane Reconstruction Costs), 39.905(b)(1) (Energy Efficiency Cost Recovery).

[877] While the price of RECs at any point in time are set by the market, presumably a purchaser has some ability to seek relatively better terms—such as making an effort to accurately forecast the number of credits required and perhaps purchasing or contracting to purchase available credits beforehand if prices are favorable, seeking volume discounts, banking excess credits when prices are favorable, etc.

[878] Schedule Q-8.8 at 45.4.

would carry forward and could be recovered in future filings. Also, the single rate could result in cost-shifting between customer classes, as over- or under- recoveries resulting from billing determinant forecast error would vary by customer class. Finally, Mr. Abbott stated, the ETI's proposed billing determinants are based on a historical year. But if load grows over the long term, this will lead to persistent over-recovery of the REC Rider revenue requirements, as Rate Year billing determinants will tend to exceed the historical billing determinants systematically.[879]

Based on these concerns, Mr. Abbott recommended that the Commission deny ETI's request for a REC Rider, and that the ETI's Test Year REC costs of $623,303 be included in base rates. Additionally, he recommended that the Renewable Portfolio Standard Calculation Opt-Out Credit Rider should be maintained; however, the credit rates should be updated to reflect the Test Year data used to set ETI's base rates. In the alternative, if the Commission approves the REC Rider requested by ETI, Mr. Abbott recommended the following changes from the Company's request:

- The REC Rider should be set every year to collect the previous year's actual REC costs (instead of projected REC costs), plus any over- or under- recovery from prior periods.
- The previous year's actual REC costs should be allocated to each customer class based upon each class's actual energy usage over the time period for which the RECs were acquired.
- Any over- or under- recovery balances should be tracked by each customer class, and thus a separate REC Rider rate should be calculated for each customer class based on that class's allocated REC costs adjusted by that class's over- or under- recovery balance.
- The REC Rider rates should be calculated using billing determinants based upon ETI's best forecast of each customer class's energy usage over the rider's Rate Year.[880]

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[879] Staff Ex. 7 (Abbott Direct) at 13-14.

[880] Staff Ex. 7 (Abbott Direct) at 14-15.

3. ETI's Response

ETI contends that adoption of the rider does not result in piecemeal ratemaking because these are the types of costs that the Company cannot control. Ms. LeBlanc believes that there is a greater risk of over-recovery of REC costs through base rates than there would be under the proposed rider.[881]

As to the issue that the Company would be disincentivized to purchase RECs at an appropriate time, ETI claims that the proposed rider has a true-up mechanism that would allow for review. ETI disputes State Agencies' claims that ETI could have purchased RECs at a lower level at other points in the year, stating there is no evidence that the Company could have bought RECs at a lower level at other points in the year.

Finally, ETI takes issue with the parties' argument that there is no statutory recovery for REC costs outside of base rates. ETI argues that there is no statutory authority requiring the Company to refund costs to opt-out industrial customers. According to ETI, no explicit statutory authority is necessary, and the parties have failed to establish that any harm would result from implementation of the rider.

4. ALJs' Analysis

The ALJs are persuaded by the testimonies of Staff and intervenor witnesses Pevoto, Nalepa, Abbot, Benedict, and Brazell that ETI's proposed REC rider should be rejected. The testimony supports a finding that adoption of the rider results in piecemeal ratemaking. ETI's argument that costs are volatile and, therefore, should be isolated and recovered in a manner similar to an annual fuel factor filing was not supported by sufficient evidence. Additionally, the ALJs agree that the proposed rider eliminates any incentive for ETI to minimize the costs of purchasing the required RECs. ETI proffered unconvincing argument and insufficient evidence that standard cost recovery was insufficient for ETI to recover its total REC costs and a reasonable return.

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[881] ETI Ex. 55 (LeBlanc Rebuttal) at 11.

The ALJs further find that the Test Year expense of $623,303 should be used for setting rates in this case.[882] ETI failed to proffer sufficient evidence and argument to support any increase to its initial request through rebuttal testimony. As recommended by Staff witness Abbott, the Renewable Portfolio Standard Calculation Opt-Out Credit Rider should be maintained, with an adjustment to the credit rates to reflect the Test Year data used to set ETI's base rates.

B. Class Cost Allocation [Germane to Preliminary Order Issue No. 14]

A cost-of-service study is an analysis used to determine the responsibility for a utility's costs for each customer class. Thus, it determines whether the revenues a class generates cover that class's cost-of-service. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics.

The parties generally agreed that ETI's cost-of-service study comported with accepted industry practices, but some parties had issues with specific items discussed below.

1. Municipal Franchise Fees

Municipal Franchise Fees (MFF) are charges for a utility's use of municipal rights-of-way. The charges are levied by municipalities based on the amount of electricity sold within the municipal boundaries. They are also referred to as street rental taxes. The MFF charged to ETI are based on ordinances passed by the cities in which ETI makes retail sales. Different cities have enacted different levels of MFF on in-city kWh sales, ranging from 0.0956¢ to as much as 0.2644¢ per kWh.[883] For the portion of fees ETI collects through base rates, ETI proposes to allocate among customer classes based on customer class revenues relative to total revenues.[884] Once MFF costs are

[882] This is the amount referenced in Ms. LeBlanc's testimony at ETI Ex. 31 at 24 and confirmed in State Agencies Ex. 9.

[883] TIEC Ex. 1 (Pollock Direct) at 52 and Ex. JP-9. Nineteen cities also charge MFF through separate "Incremental Franchise Fee Recovery" Riders. These incremental MFF are not included in ETI's proposed revenue requirements in this case. TIEC Ex. 1 (Pollock Direct) at 53.

[884] Schedule P-13 at10, lines 32-33; the allocation factor "RSRRTOA-Total" is rate schedule revenue.

allocated to the rate classes, ETI proposes to collect the costs from all customers regardless of their geographic location.[885]

ETI proposes the same allocation and collection of MFF in this case as was approved by the Commission in Docket No. 16705, ETI's last litigated rate case.[886] The positions of the parties, as set out in testimony and briefs, are listed below:

Party/Precedent	MFF Allocation Between Customer Classes By:	Collection of MFF Expenses From:
ETI	Total revenues	All customers
Cities	Total revenues	All customers
OPC	kWh sales in city	All customers
Staff	kWh sales in city	All customers
TIEC	Franchise fee payments in city	Only from municipal customers
Docket No. 16705	Total revenues	All customers

(a) MFF Allocation Between Customer Classes

Cities and ETI recommend adoption of ETI's proposal to allocate to customer classes based on total rate schedule revenues, which the Commission approved in Docket No. 16705. ETI notes that it is following Commission precedent, and it opposes the use of different allocation factors for these FERC accounts: Account 408.152, Franchise Tax State; Account 408.154 Franchise Tax Local; and Account 408.163, Street Rental.

OPC witness Benedict testified that MFF should be allocated on the basis of in-city kWh sales, without an adjustment for the MFF rate in the municipality in which a given kWh sale occurred. Staff witness Abbot concurs. Stated differently, Messrs. Benedict and Abbot suggest allocating MFF relative to each class's inside-city kWh sales with the same MFF per unit cost (*i.e.*,

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[885] OPC Ex. 8 (Benedict Cross Rebuttal) at 9.

[886] *Application of Entergy Gulf States, Inc. for Approval of Its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs,* Docket No. 16705, Second Order on Rehearing at 98 (FoF 224) (Oct. 13, 1998).

0.1965¢ per kWh) for all customer classes.[887] Mr. Benedict noted that this allocation method is based on Commission precedent, as indicated in the recent CenterPoint rate case, Docket No. 38339:

> CenterPoint's allocation of municipal franchise fees to the customer classes based upon in-city kilowatt-hour (kWh) sales and collection of the fees from all customers within the customer class is reasonable and consistent with Commission precedent.[888]

Mr. Benedict also noted that allocating on the basis of in-city kWh sales is consistent with PURA § 33.008(b).[889]

Commission Staff supports Mr. Benedict's analysis. Staff points out that PURA § 33.008(b), which authorizes the collection of municipal franchise fees, states that "[t]he compensation a municipality may collect from each electric utility . . . shall be equal to the charge per kilowatt hour . . . times the *number of kilowatt hours delivered within the municipalities boundaries*."[890] According to Staff, PURA § 33.008(b) plainly links the amount of municipal franchise fees to each class's in-city kWh sales. Moreover, the Commission has an established policy of allocating municipal franchise fees based on in-city kWh sales.[891] According to Staff, the Commission should reaffirm

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[887] *See* OPC Ex. 7 (Benedict Cross Rebuttal) at 4-5; Staff Ex. 7 (Abbott Direct) at 22; TIEC Ex. 3 (Pollock Cross Rebuttal) at 34.

[888] OPC Ex. 6 (Benedict Direct) at Ex. NAB-1, *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates,* Docket No. 38339, Order on Rehearing at 34, (FoF 179) (June 23, 2011).

[889] OPC Ex. 7 (Benedict Cross Rebuttal) at 5.

[890] PURA § 33.008(b)(emphasis added).

[891] *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule 25.344*, Docket No. 22350, Order at FoF 156 (Oct. 4, 2001). The Commission reached an identical conclusion in *Application of Reliant Energy HL&P for Approval of Unbundled Cost of Service Rate Pursuant to PURA 39.201 and Public Utility Commission Substantive Rule 25.344*, Docket No. 22355, Order at FoF 222A (Oct. 4, 2001). More recently, *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Rehearing at FoF 179 (June 23, 2011) (stating that "CenterPoint's allocation of municipal franchise fees to the customer classes based upon in-city kilowatt-hour (kWh) sales and collection of the fees from all customers within the customer class is reasonable and consistent with Commission precedent.").

Staff notes in their initial brief that the Commission has further indicated that this allocation should be conducted without any adjustment for differences in the rates charged by individual municipalities within a utility's service territory. *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing at FoF 150 (Mar. 4, 2008) (stating in connection with a proposed municipal franchise fee expense rider that "[h]aving different rates in each municipality in TCC's service territory is contrary to the Commission's desire for uniform, simple rates").

this precedent in this case by allocating ETI's MFF to each customer class on the basis of in-city kWh sales.

TIEC witness Pollock disagrees with OPC's and Staff's proposed allocation method, although Mr. Pollock stated their proposal was better than ETI's proposed allocation. He believes OPC's and Staff's proposal fails to recognize the different MFF rates charged by cities. Because cities that have a preponderance of industrial sales generally charge lower MFF rates, this proposal would require LIPS customers to pay 0.1965¢ per kWh, which is more than the weighted average MFF cost to the LIPS class of 0.1612¢ per kWh. Thus, Mr. Pollock argues that this would require LIPS customers to subsidize other customer classes and would not be consistent with cost causation. Mr. Pollock thought his proposal to allocate MFF by city by class resulted in each customer class paying only the MFF expenses actually incurred.[892]

The ALJs find OPC's and Staff's proposed allocation methodology best comports with PURA § 33.008 and Commission precedent. As noted by Mr. Benedict, PURA was amended after the Commission's decision in Docket No. 16705, which allocated MFF on the basis of rate schedule revenue. PURA § 33.008 expressly calls for a kWh basis for allocation and this is confirmed in the cases litigated since Docket No. 16705, which were cited by Commission Staff. Accordingly, the ALJ recommend that MFF be allocated on the basis of in-city kWh sales, without an adjustment for the MFF rate in the municipality in which a given kWh sale occurred.

(b) MFF Collection

All parties except TIEC recommend that the Commission approve ETI's proposed allocation of franchise fee rentals to all customers. Cities witness Mr. Brazell testified that franchise fees are in the nature of a rental, not a tax, and like all rental charges ETI incurs, the expense should be spread among all customers. He stated that MFF charges have always been collected from all customers, whether or not they take service within the corporate limits, except for the limited incremental franchise fees specifically addressed by PURA § 39.456. Mr. Brazell explained that electrical facilities within ETI's system are physically interconnected and electrically synchronized. The

[892] TIEC Ex. 3 (Pollock Cross Rebuttal) at 8, 33-35.

facilities located within a city's boundaries are not isolated physically or electrically from the facilities outside the city limits. Rather, they are tied to one another and function as a single integrated system, and ETI's facilities inside each city benefit all customers in ETI's service area, whether or not those customers are within the city. Therefore, Mr. Brazell recommended that the Commission approve ETI's request to recover MFF in base rates from all customers.[893]

Mr. Benedict holds the same opinion. He stated that the Commission's policy to collect MFF from all customers within a customer class is also consistent with the concept that MFF are system costs that are rightly paid by all customers taking service from the system. He explained that MFF are paid by a utility to municipalities for use of the municipalities' rights-of-way. Because these rights-of-way are necessary to operate an integrated electric delivery system from which all customers benefit, regardless of geographic location, Mr. Benedict stated that MFF should be collected uniformly from all customers within a given rate class. He stressed that the Commission agreed with this reasoning in Docket No. 16705, where the Commission concluded:

> Current cost of services studies are not based on geographical differences. Classes are not divided based on geography, and industrial sites are not self-sufficient islands. The use of city streets and property enables [EGSI] to have an integrated utility system from which all ratepayers benefit.[894]

Mr. Pollock objected to the proposals by Mr. Brazell and Mr. Abbott. He stated that Mr. Brazell's recommendation to adopt ETI's proposed MFF allocation should be rejected because there is no evidence that outside city customers benefit from ETI's use of city streets and rights-of-way or that the benefits are evenly distributed between inside and outside city customers. Further, according to Mr. Pollock, the standard used in class cost-of-service studies is cost causation, not benefits, and he believes allocating MFF based on outside city usage is contrary to cost causation principles.[895]

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[893] Cities Ex. 1 (Brazell Direct) at 28-32.

[894] OPC Ex. 6 (Benedict Direct) at Ex. NAB-2, Docket No. 16705, Second Order on Rehearing at 98, (FoF 224).

[895] TIEC Ex. 3 (Pollock Cross Rebuttal) at 7, 32-33.

The ALJs recommend adoption of ETI's proposal to collect costs from all customers taking service from the system. The ALJs find persuasive the fact that MFF is compensation for the use of municipalities rights-of-way, which is used to operate an integrated electric delivery system from which all customers benefit.

2. Miscellaneous Gross Receipts Taxes

Miscellaneous gross receipts taxes (MGRT) are state taxes imposed on each utility company's taxable gross receipts derived from sales in an incorporated city or town having a population of more than 1,000. Like MFF, these taxes are levied only on sales within the cities. ETI proposes to allocate MGRT to all retail customer classes based on customer class revenues relative to total revenues.[896]

TIEC objects to ETI's allocation of MGRT based on class revenues for the same reasons stated for ETI's allocation of MFF. It argues that these costs should be allocated and charged to customers within the municipalities to which the MGRT applied.

The allocation of MGRT is similar to the allocation of MFF and should be similarly applied. For the reasons set out above and to ensure consistent treatment, the ALJs do not recommend the direct method of allocation suggested by TIEC. Rather, these costs should be allocated to the rate classes according to ETI's cost of service study.

3. Capacity-Related Production Costs

(a) Allocation Methodology

ETI proposes to allocate capacity-related production and transmission costs to the retail classes on the basis of A&E 4CP. As noted by TIEC and Commission Staff, this allocation methodology is consistent with the method ETI used in Docket No. 16705, its last contested rate proceeding:

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[896] ETI Ex. 3, Schedule P-13 at 10, line 34.

> Finding of Fact No. 221. The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use through the year.
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> Finding of Fact No. 222. The A&E 4CP method is also preferable because it is devoid of any double counting problem.[897]

ETI witness Ms. Talkington explained that the A&E 4CP allocation is appropriate because it is a method that reasonably reflects the mix of the Company's customers, their respective electrical load characteristics, and the relative costs incurred to serve such loads. She testified that the A&E 4CP method provides a reasonable balance between the two primary costing concerns: contribution to the system peak and energy requirements. While the contribution made to the system peak is inherently recognized with the use of the average four coincident peaks, energy is also recognized by reflecting the average demands.[898]

OPC witness Benedict proposed the use of the average and single coincident peak (A&P) method to allocated production (and transmission costs, which are discussed in the section below) among retail classes. As noted in the discussion concerning jurisdictional allocation, A&E 4CP is a variant of the A&E allocator. Mr. Benedict believes that A&E 4CP fails to properly assign cost responsibility to both peak and off-peak usage.[899] Instead, he found that the A&E 4CP allocator results in the same factors reached by the 4CP method, which means that A&E 4CP assigns cost responsibility only to peak demand and not to off-peak demand. He believes that the A&P

[897] Docket No. 16705, Second Order on Rehearing at 97, FoF 221 and 222 (Oct. 14, 1998).

[898] ETI Ex. 22 (Talkington Direct) at 5. As noted previously, A&E 4CP is developed by adding each rate class's average demand for the test year (the "average" component representing the rate class's average energy consumption), weighted by the ETI system load factor, to each rate class's amount of average coincident peak demand for the months of June through September in excess of its average demand, weighted by one minus the ETI system load factor.

[899] Mr. Benedict performed a mathematical proof that he believed demonstrated that the A&E 4CP allocator is nearly identical to the 4CP allocator. OPC Ex. 6 (Benedict Direct) at 21-22.

methodology is the proper plant allocator because it takes into account both peak usage and off-peak usage patterns.[900]

Mr. Benedict's methodology and recommendation was disputed by Kroger witness Higgins. He indicated that the A&E method does not converge to a CP result. Rather, the A&E method addresses a fundamentally important question in production cost allocation—once capacity needed to serve the average demand on the system is accounted for, how does the regulator fairly assign the responsibility for the additional or excess capacity that is needed to meet the various capacity requirements (placed on the system by each customer class). Mr. Higgins concluded that the A&E method makes an objective and reasonable allocation. However, he did not advocate changing ETI's use of A&E 4CP.[901]

Mr. Higgins explained that:

> [T]he Average and Excess demand method begins by allocating a portion of costs on the basis of average demand—or energy. The <u>remaining</u> (or "excess") capacity needs of the system are then allocated to classes based on peak usage—class NCP in the case of the "standard" approach, 4 CP in the case of the A&E/4CP method. In contrast, the A&P method proposed by Mr. Benedict, which is classified by the NARUC Manual as a "Judgmental Energy Weighting" approach, incorporates a subjective determination that includes the <u>full</u> value of average demand both in the "average" component of the A&P calculation as well as in the peak component of that calculation.[902]

TIEC witness Pollock also disputed Mr. Benedict's proposed methodology, stating that A&P does not reflect cost causation and is not reasonable for ETI. He believes that Mr. Benedict's support of the A&P method is based on an oversimplification of the planning process. He also noted that A&E is recognized in the NARUC Electric Utility Cost Allocation Manual and has been repeatedly used by the Commission.[903]

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900 *Id.*

901 Kroger Ex. 2 (Higgins Cross Rebuttal) at 4-5.

902 *Id.* at 6 (emphasis in originial).

903 TIEC Ex. 3 (Pollock Cross Rebuttal) at 12-14, citing the NARUC *Electric Utility Cost Allocation Manual,*

The following calculations performed by Messrs. Benedict and Higgins demonstrate the different results stemming from the allocation methodologies:[904]

Rate Class	ETI *Proposed* *A&E/4CP (%)*	OPC *Recommended* *A&P (%)*	Kroger *Standard* *A&E*	*Alternative* *12CP*
Residential	47.4494	40.1181	48.4013	43.4768
Small General Service	2.0990	2.0595	2.7209	2.0169
General Service	18.0259	19.4933	18.5183	18.6122
Large General Service	7.0794	8.3822	6.6558	7.4339
Lg. Indust. Power Serv.	20.4401	25.5485	20.2122	22.9417
Total Lighting	0.2900	0.2768	0.4042	0.1394
Total Texas Retail	*95.3838*	*95.8784*	*96.9127*	*94.6208*
Total Wholesale and Wheeling	4.6162	4.1216	3.0873	5.3792
Total Company	*100.0000*	*100.0000*	*100.0000*	*100.0000*

The ALJs recommend the use of A&E 4CP to allocate capacity-related production costs, as proposed by ETI. The weight of the evidence as well as Commission precedent does not support the methodology proposed by Mr. Benedict. A&E 4CP was approved for the Company in Docket No. 16705, and the extensive testimonies (which included calculations and graphs) of Messrs. Higgins and Pollock indicate that, not only is the methodology frequently adopted by the Commission, it is also a standard and reasonable methodology. As noted by ETI, it reasonably reflects the mix of the Company's customers and their respective load characteristics and the relative costs incurred to serve such loads. It recognizes the contribution of both peak demand and the pattern of capacity use throughout the year.[905] It also recognizes that ETI, like all Texas utilities, is a summer peaking utility. The ALJs recommend that ETI's allocation of capacity production costs be adopted.

January 1992.

[904] OPC Ex. 6 (Benedict Direct) at 25; Kroger Ex. 2 (Higgins Cross Rebuttal) at 5.

[905] *See* Docket No. 16705, Second Order on Rehearing at FoF 221 (Sept. 4, 1998).

(b) Reserve Equalization Payments

A subset of the Company's requested capacity-related production costs relate to reserve equalization payments made by the Company pursuant to the Entergy System Agreement (Service Schedule MSS-1). The System Agreement, which is approved by the FERC, prescribes a method by which each Entergy Operating Company's share of Entergy system reserves are calculated. ETI, as one of the Operating Companies, is responsible to provide the system with its allocated share of system reserves. Some Entergy Operating Companies own less than their share of system reserves and are considered "short" with respect to generation capability. Companies that own more than their share are considered "long" companies. Short companies make payments to long companies pursuant to the terms of the System Agreement. Because ETI is a short company, it makes reserve equalization payments which are included in the cost of service.[906]

ETI allocates MSS-1 payments using A&E 4CP. Mr. Benedict argues that this allocation method is not consistent with the way costs are incurred, as ETI does not make MSS-1 payments on the basis of A&E 4CP. According to Mr. Benedict, ETI incurs costs by being short with respect to system reserves—the payment is simply the number of MW by which it is short, multiplied by a $/MW rate as determined by a contract formula. The degree to which ETI is short is determined by comparing its generation capability to its allocated share of system reserves. Total system reserves are allocated to the other Operating Companies on the basis of the Responsibility Ratio. Thus, as determined by the Responsibility Ratio, ETI's share of system reserves relative to its generating capability is what causes ETI to make MSS-1 Reserve Equalization payments.[907]

Mr. Benedict concluded that, because Reserve Equalization payments are incurred on the basis of ETI's Responsibility Ratio, which is a rolling 12CP allocator, the payments should be allocated to ETI's rate classes on a similar basis. As a result, he recommended that Reserve Equalization payments be allocated on the basis of 12CP.[908]

[906] OPC Exhibit No. 6 (Benedict Direct) at 29-30.

[907] *Id.*

[908] *Id.* at 31.

According to OPC, Mr. Benedict's proposal for allocating MSS-1 payments has been criticized because 12CP measures class demands at ETI's peak monthly demands whereas the Responsibility Ratio is measured at the Entergy system's peak monthly demands. OPC agrees that 12CP uses peak hours that may differ from those used to compute the Responsibility Ratio, but contends that the Company fails to mention that the A&E 4CP method it uses to allocate MSS-1 payments is also subject to the same critique. When choosing between the 12CP allocator and the A&E 4CP allocator for the purpose of allocating reserve equalization payments, OPC believes 12CP is more desirable. ETI's contributions to the Entergy system's peaks in all 12 months, not just the four summer months, determine ETI's share of Entergy system reserves. ETI's share of system reserves, relative to its generation capability, is what causes reserve equalization payments to the other Entergy Operating Companies. Moving to a 12CP allocation for MSS-1 payments aligns cost allocation more closely with cost causation.

TIEC witness Pollock explained that the Entergy System Agreement is regulated by the FERC, which does not control the rate design policy applicable to Texas retail customers under Commission jurisdiction. He views the System Agreement as an accounting mechanism to equalize the benefits and costs associated with interconnected operation and joint planning. In his opinion, it is not relevant to determining which production capacity allocation method best reflects cost causation for Texas retail customer. According to Mr. Pollock, the MSS-1 payments are no different in concept from the costs associated with ETI's high-voltage transmission lines, which are allocated on an A&E 4CP basis. He further indicated that the 12CP method ignores the reality the ETI is a predominantly summer peaking utility.[909]

The ALJs do not find sufficient support to allocate the reserve equalization payments differently than other capacity-related production costs. For the same reasons noted in the section above, the ALJs find the weight of the evidence supports allocation using A&E 4CP. While 12CP is a reasonable methodology for jurisdictional separation between retail and wholesale entities, the evidence does not support this methodology for allocation of reserve equalization payments.

[909] TIEC Ex. 3 (Pollock Cross Rebuttal) at 27-29.

4. Transmission Costs

As noted above, ETI also allocates transmission costs using the A&E 4CP methodology. Again, TIEC and Staff cite to the Commission's decision in Docket No. 16705, which adopted the A&E 4CP approach for both production and transmission costs. OPC witness Benedict, however, proposes allocating transmission plant using A&E methodology that he proposed for the allocation of production plant.[910]

TIEC argues that methodologies similar to Mr. Benedict's proposal have been repeatedly rejected by the Commission, and the A&E 4CP methodology has been repeatedly approved. TIEC suggests that Mr. Benedict offers no rationale for a different result for transmission costs. According to TIEC, the rationale that he offers for using the A&P method for production costs—the potential trade-off between capital costs and fuel costs—is entirely absent with respect to transmission plant. Mr. Benedict does not even assert that such trade-offs exist. Rather, the only basis he offers for using the average and peak methodology is his assertion that the A&E 4CP allocator "mathematically reduces to a 4CP allocator."[911] TIEC points out that the Commission, by rule, has adopted the 4CP method for the allocation of transmission plant within ERCOT.[912]

ETI witness Talkington indicated the same reasons and rationale for using the A&E 4CP methodology to allocate transmission costs as she noted for capacity-related production costs.[913]

Kroger witness Higgins also disputed the use of A&E 4CP for allocation of transmission costs for the same reasons noted above concerning production cost allocation. Moreover, he compared the different allocation factors—specifically, ETI's proposed A&E 4CP, the A&E, and

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[910] OPC Ex. 6 (Benedict Direct) at 26-28.

[911] TIEC Initial Brief at 68, *citing* OPC Ex. 6 (Benedict Direct) at 27.

[912] P.U.C. SUBST. R. 25.192 specifically provides that transmission costs are allocated based on the "coincident peak demand for the months of June, July, August, and September (4CP) . . . ."

[913] ETI Ex. 67 (Talkington Rebuttal) at 8-9.

Mr. Benedict's recommended A&P. His calculations indicated that A&E 4CP and the A&E produce similar results, while A&P radically departs from ETI's proposed allocations.[914]

The ALJs do not find sufficient or persuasive evidence to change ETI's proposed methodology for allocation of transmission costs. A&E 4CP is a well-accepted method for allocating such costs, which the Commission has repeatedly adopted. The ALJs recommend the use of the A&E 4CP to allocate ETI's transmission costs.

C. Revenue Allocation

Wal-Mart, Kroger, TIEC, and Commission Staff advocate that the rates be set on the basis of the utility's costs of service. These parties recommends the adoption of ETIs proposed base rate revenue allocation, recovering from each class 100 percent of it respective Test-Year base rate costs per the revenue requirement ultimately adopted.

TIEC witness Pollock testified that revenue allocation is the process of determining how any base revenue change approved by the Commission should be spread to each customer class served by the utility. ETI proposed an overall increase in non-fuel revenues of 17.53 percent, but the increase is not spread proportionally to all the classes.[915] Rather, ETI proposed class revenue requirements that are closely aligned with the Company's proposed cost of service. Set out below is the impact of ETI's proposed base rate increase for each class:[916]

Class	Change in Base Revenues
Residential	25.10%
Small General Service	1.82%
General Service	5.54%
Large General Service	19.06%
Large Industrial Power Service	11.17%

[914] Kroger Ex. 2 (Higgins Cross Rebuttal) at 5-6.

[915] ETI's revenue requirement does not include the costs associated with its requested REC Rider.

[916] *See* Kroger Ex. 1 (Higgins Direct) at 5-6; *see also* Cities Ex. 6 (Nalepa Direct) at 34.

Lighting Service	29.36%
System Average	*17.53%*

The contested issue concerns whether rates should be set at cost, and any approved change in base rate revenues should reflect the actual cost of providing service, or whether any rate increase should be phased in for certain classes (notably Residential and Lighting classes) to reduce the impact (rate shock)

1. Argument for Moving Rates to Cost

ETI and the parties in support of ETI's class revenue allocation contend it is appropriate to set rates at each class' cost of service as ETI has proposed in order to avoid continuing inappropriate and inequitable cost shifting between customer classes. TIEC witness Mr. Pollock testified that cost-based rates send the proper price signals to customers. He noted other reasons for using cost-of-service principles: equity, engineering efficiency (cost-minimization), stability, and conservation. If rates are not based on cost, then some customers subsidize part of the cost of providing service to other customers. Moreover, he suggested that by providing balanced price signals, cost-based rates encourage conservation and may prevent waste or inefficient use. If rates are not based on a class cost-of-service study, then consumption choices can be distorted.[917]

Mr. Pollock developed a class revenue allocation based on his proposed jurisdictional and class cost-of-service studies. If these recommendations are adopted, his class revenue allocation produced the following results:

Rate Class Service	Present Non-Fuel Revenues	Proposed Base Revenue Increases	Percent Increase
Residential	$379,382,000	$80,390,000	21.2%
Small General	$26,430,000	$283,000	1.1%
General	$159,768,000	$9,797,000	6.1%
Large General	$49,380,000	$8,714,000	17.6%

917 TIEC Ex. 1 (Pollock Direct) at 63-65.

Rate Class Service	Present Non-Fuel Revenues	Proposed Base Revenue Increases	Percent Increase
Large Indus. Power	$104,308,000	$9,862,000	9.5%
Lighting	$10,813,000	$2,143,000	19.8%
Total	$730,080,000	$111,189,000	15.2%

As discussed below, Mr. Pollock also recommended lower rates for Schedules SMS and AFC, which would reduce ETI's revenues by about $2 million. To offset this loss, he testified that revenues would need to be increased for other classes to achieve the total increase requested by ETI. These changes would produce the following results:[918]

Rate Class Service	Present Non-Fuel Revenues	Proposed Base Revenue Increases	Percent Increase
Residential	$379,382,000	$81,500,000	21.5%
Small General	$26,430,000	$340,000	1.3%
General	$159,768,000	$10,205,000	6.4%
Large General	$49,380,000	$8,860,000	17.9%
Large Indus. Power	$104,308,000	$10,153,000	9.7%
Lighting	$10,813,000	$2,160,000	20.0%
Total	**$730,080,000**	**$113,218,000**	**15.5%**
SMS/AFC Impacts	$13,816,000	($2,029,000)	-14.7%
Total Sales	$743,896,000	111,189,000	14.9%

If the Commission disallows other elements of ETI's rate request, Mr. Pollock testified that class revenue allocation should be reduced in accordance with how such disallowed costs were allocated to each rate class.[919]

Mr. Pollock's tables provide examples of the impact on each class of customers when the Commission makes final decisions concerning the Company's proposed rate design and the final revenue requirement.

[918] *Id.* at 63-67 and Exs. JP-12 and JP-13.

Staff witness Abbott testified that the Commission ordinarily sets rates for each customer class to recover the costs incurred by the utility to serve that class. In this case, ETI's proposed revenues for all customer classes result in base revenues that are close to the cost of service allocated costs. No single customer class' proposed revenue requirement differs from ETI's calculated cost to serve that class by more than 3 percent. Staff acknowledges that certain classes face proportionally larger rate increases to bring them closer to unity, where revenue recovery is based on actual cost of service. However, Staff agrees with Mr. Pollock that setting each customer class at their cost of service avoids inflating rates for some customer classes and subsidizing the usage of others. Staff believes that recovering from each class its respective base rate cost is equitable and provides appropriate pricing signals to facilitate the most efficient use of resources in the provision and consumption of electricity. Staff also argues that the Commission has approved such class cost of service allocation in recent rate cases.[920]

Wal-Mart and Kroger concur with Staff and TIEC.

2. Argument for Gradualism

Cities witness Karl Nalepa pointed out that, under ETI's proposed rates, the Residential and Lighting customer classes receive the highest rate increases while the Small General Service, General Service, and Large Industrial Power Service classes receive below system average rate increases of 1.62 percent, 4.81 percent, and 10.77 percent, respectively. However, he examined Test Year customer quantities, energy and loads by customer class for each of ETI's last three cases, and he concluded that residential and lighting customers are not imposing an undue cost burden on the system. Instead, other classes are growing at a faster rate, causing system costs to increase. Moreover, Mr. Nalepa testified that a number of events are occurring with the Entergy system that will have significant impact on costs, including: Entergy's efforts to join MISO; plans by EAI and

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919 *Id*. at 67.

920 Staff cites *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 28339, Order at FoF 175 (May 12, 2011) and Docket No. 16705, Second Order on Rehearing at FoF 245 (Sept. 4, 1998). TIEC witness Pollock also testified that Commission precedent supports allocation of costs based on the cost of service study. He also cited to the CenterPoint case and to *Application of AEP Texas Central for Authority to Change Rates, Docket No. 28840,* Order at 50 (Aug. 15, 2005). TIEC Ex. 1 (Pollock Direct) at 65.

EMI to leave the Entergy System Agreement; and the possible divestiture of the transmission system by all Entergy Operating Companies. Given these uncertainties, Mr. Nalepa proposed that any rate increase or decrease be spread proportionately across the system classes. Then, once Entergy and ETI address the proposed system cost changes, a reasonable class cost allocation study can be presented.[921]

State Agencies do not take a position on overall class revenue allocation but request that ETI's proposed rate increase for the Lighting class be moderated. ETI proposes to set base rate revenues for the Lighting class based on the class cost allocation study, without any adjustment, which would result in a 20.38 percent increase to the Lighting class, when the entire ETI system would receive a 15.32 percent increase. Thus, under ETI's proposal, this class would receive a percentage increase about 1.33 times the system average. Ms. Pevoto contended that that this increase would be excessive and would create significant rate shock to the class. Because the services of the Lighting class provides benefits all customers on the system, Ms. Pevoto believes it would be reasonable to mitigate the rate shock so that lighting customers can afford to continue their lighting service. Otherwise, she suggested, some lighting customers may reduce lighting services or refrain from ordering additional lights. This, in turn, would adversely affect the benefits that lighting service provides to the public.[922]

Ms. Pevoto also pointed out that in 2009, the Commission adopted a rate moderation proposal for a similar rate class served by another utility. In that case, the Commission recognized that the Lighting class was unique in the combination of the public good it performs and in its demand characteristics.[923] To mitigate the rate shock on the lighting customers in the present case, Ms. Pevoto recommended a cap on any base rate increase that would be equal to the smaller of: (1) the lighting class percentage rate increase resulting from the PUC-approved cost of service allocation study, or (2) the allowed system percentage rate increase. If the percentage rate increase is smaller than the allowed system percentage rate increase, then no mitigation adjustment would be

[921] Cities Ex. 6 (Nalepa Direct) at 34-37.

[922] State Agencies Ex. 2 (Pevoto Direct) at 12-13.

[923] *Application of Oncor Electric Delivery Company for Authority to Change Rates*, Docket No. 35717, Order on Rehearing at 32 (Nov. 30, 2009).

necessary. However, if the PUC-approved cost of service allocation results in a percentage base rate increase for the lighting class that is greater than the allowed system percentage increase, then she urged that a mitigation reduction should occur. She also proposed that any mitigation reduction for the lighting class should be spread to other remaining classes, based on each class' cost of service.[924]

ETI argues that the State Agencies are proposing the continuation of a significant subsidy by other classes. The Company notes that its allocation of costs to the Lighting class is based on the revenue requirement developed for that class. ETI acknowledges that its proposed increase for the Lighting class is 20.38 percent greater than the system average increase, but it is less than the Residential class's proposed increase of 21.64 percent. ETI witness Ms. Talkington testified that the Company does not support any subsidies between rate classes. She testified that previous rate cases with subsidies for the Lighting class have pushed the class farther away from cost.[925]

OPC argues that cost of service should not be the sole factor in setting rates and that gradualism should be used in appropriate circumstances. OPC witness Benedict disagreed with Mr. Pollock's (and Staff's) citation to the CenterPoint and AEP TCC rate cases to reject the concept of gradualism because both CenterPoint and TCC are unbundled transmission and distribution (T&D) utilities whose charges had a small impact on retail customers' total bill. He noted that the number runs for TCC and CenterPoint showed retail revenue increases of only 0.14 percent and 1.30 percent, respectively, with some classes receiving rate decreases.[926] Mr. Benedict cited the following language by the Commission in its Order for the TCC case:

> The Commission declines to adopt gradualism in this case. This proceeding develops the T&D rates, as opposed to the broader rates developed for a fully integrated utility. As the T&D rates are only a subset of the total rates paid by customers, changes to the T&D rates would not have as large an impact as they

[924] State Agencies Ex. 2 (Pevoto Direct) at 15-16.

[925] ETI Ex. 67 (Talkington Rebuttal) at 18-19.

[926] OPC Ex. 8 (Benedict Cross Rebuttal) 11-12; Ex. NAB-4, Docket No. 28840, TCC Number Run (July 21, 2005); and Ex. NAB-5, Docket No. 38339, Revised Number Running Schedules (Feb. 18, 2011).

would if the broader rates for a customer class were changed by the same percentage. . . .[927]

In Mr. Benedict's opinion, gradualism should be employed when setting rates for ETI because ETI is an integrated utility and has proposed a large rate increase.[928]

Mr. Benedict also emphasized the imprecise nature of a cost of service study. He noted that ETI's cost of service study had 47 allocation factors and, even at the summary level, 22 expense categories and 24 rate base categories.[929] Thus, he stated, there are a host of decisions made by the cost of service analyst which, in combination with the various account entries, yield a class' reported cost of service. Mr. Benedict also pointed to disagreement among qualified experts on the "correct" allocation for certain classes of costs.[930] In addition to these allocation questions, Mr. Benedict stated that any disallowances made to ETI's requested costs will have asymmetric effects on class cost of service depending on how the costs were allocated. Thus, while the cost of service study is an important element of ratemaking, Mr. Benedict stressed that it is not the only consideration.[931]

Due to the wide variation of rate increases obtained from ETI's cost of service study, Mr. Benedict thought that rate moderation (gradualism) would be appropriate. However, he added, until decisions are made regarding the cost disallowances and allocation modifications proposed by the parties, it is unclear which rate classes should be granted rate moderation and the degree to which rate moderation is needed. Mr. Benedict said that the system average rate increase should be used as a benchmark for rate moderation, but not assigned uniformly to all classes as Mr. Nalepa proposed or to just one class as Ms. Pevoto suggested. Instead, he believed it would be reasonable to establish

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927 *Id. citing* Docket No. 28840, Order at 23 (Aug. 15, 2005).

928 OPC Ex. 8 (Benedict Cross Rebuttal) at 9-14.

929 Allocation factors are provided in Schedule P-7.1; Expenses are summarized in Schedule P-7.4; Rate Base is summarized in Schedule P-7.5.

930 He noted, for example, that his direct testimony and Mr. Nalepa's direct testimony proposed a different allocation methodology for production-related capacity costs, transmission costs, and certain System Agreement costs. Mr. Pollock proposed a different allocation method for municipal franchise fees and local gross receipts taxes. Mr. Abbott recommended different allocation methods for municipal franchise fees and other franchise taxes.

931 OPC Ex. 8 (Benedict Cross Rebuttal) at 14-17.

a floor and a ceiling for the increases in revenue from each class, such that a class' individual percentage increase in revenue requirement is within a defined range of the system's average revenue increase. Therefore, Mr. Benedict recommended that any rate increase for a particular class be restricted to a range of 0.75 to 1.25 times the system's average increase. This would result in rate increases up to 25 percent lower or 25 percent higher than the average rate increase for the system as a whole. Based on a system average increase of 17.53 percent, individual class increases would range from 13.15 percent to 21.91 percent under Mr. Benedict's proposal.[932]

3. ALJs' Recommendation

The parties presented persuasive argument on both sides of the issue. Clearly, in any rate case, movement toward unity—setting rates to cost—is appropriate when such movement does not result in rate shock to a particular class or classes. If rate shock is likely, Commission precedent supports the use of gradualism. These policies apply to both a fully integrated utility, as well as a T&D. The salient issue is whether the utility's proposed increase is so out of proportion or harsh to a particular class that some form of gradualism should be applied. In this rate case, the preponderance of the evidence does not support the use of gradualism, even for the Lighting class. While that class may receive an increase almost 1.33 times the system average increase, Commission precedent indicated an appropriate ceiling of 1.5 or even 1.75 times the system average is appropriate.[933] As to applying OPC's proposed floor and ceiling approach, this method was introduced in cross-rebuttal with no calculations depicting the impact on each class. The ALJs do not recommend its adoption because it fails to offer significant movement towards class responsibility for cost of service. The ALJs do not recommend Mr. Nalepa's suggestion to impose any revenue change on an equal percent basis because it offers no movement towards unity. Accordingly, the ALJs concur with the parties supporting ETI that revenue allocation in this case should be based on each class's cost of service and consistent with the ALJs' recommendations in the PFD that impact revenue allocation.

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[932] OPC Ex. 8 (Benedict Cross Rebuttal) at 17-19.

[933] *See* Docket No. 28840, Order at 23 (rejecting ALJs' proposed ceiling of 1.75 times the system average).

D. Rate Design [Germane to Preliminary Order Issue Nos. 15, 18, and 20]

Staff explained that the Commission has traditionally established class costs of service based on the principle of cost causation. Staff believes the Commission has consistently required substantial justification for departing from this principle when setting rates that result in cross-subsidization between customer classes. With respect to intra-class cost causation and rate design, Staff maintains that the considerations are somewhat different. Rather, the Commission has traditionally given more weight to policy considerations other than cost causation in determining intra-class rate design issues because the danger of permanent subsidies within a particular class is relatively low.[934] For instance, Staff witness Abbott testified that customer usage within a class may vary throughout the year. He noted that a low-load-factor customer might become a high-load-factor customer, resulting in a different mix of charges throughout the year.[935] While an individual customer's usage characteristics might frequently change and thereby lessen the impact of cost shifting within a class, Mr. Abbott testified that such customers were unlikely to shift to a different customer class.[936] While subsidies in the customer class allocation context might be permanent, this was not necessarily the case for intra-class rates. Moreover, these shifting usage characteristics make it more difficult to identify cost drivers within a rate class. Staff suggests that consideration be given to policies such as customer impact and energy efficiency.

The ALJs agree with Staff's analysis. Mr. Abbott recommended that the Commission apply gradualism—limiting the magnitude of rate changes—to help stabilize customer expectations and reduce risk.[937] ETI witness Talkington also advised caution in response to suggested changes to ETI's proposed rate design, noting that the ultimate impact on a customer's bill is important.[938] However, the ALJs' rate design recommendations are based on the evidence and argument for each

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[934] Staff cites to Mr. Abbott's cross-examination at Tr. at 1818 ("Q: And is there a distinction between factors that you would consider such as costs or other factors when you're discussing class allocation as opposed to rate design issues? A: I would say there are different considerations and weights to considerations and the analysis of allocating costs to classes versus the analysis of allocating costs to rates within a class.").

[935] Tr. at 1818.

[936] *Id.*

[937] Staff Ex. 7 (Abbott Direct) at 25-26.

[938] ETI Ex. 67 (Talkington Rebuttal) at 16.

customer class or rate schedule. Thus, the ALJs' recommendation on the specific rates or charges for the industrial customers will impact all other customer classes but that impact is not known at this time.

1. Lighting and Traffic Signal Schedules

Cities witness Dennis W. Goins explained ETI's Lighting and Traffic Signal Schedules. ETI's principal rate schedule for street lighting customers is Schedule SHL (Street and Highway Lighting Service), while Schedule TSS (Traffic Signal Services) is the principal rate schedule for ETI's traffic lighting customers that own and maintain their lighting facilities. For Schedule SHL, the rate includes four categories of service (Rate Groups A, C, D, and E). Rate Group A includes ETI's standard fixture and lamps mounted on existing standard wood poles that ETI installs and maintains. If a customer wants nonstandard lighting facilities (those not provided in Rate Group A), the customer is assigned to Rate Group C and required to prepay ETI for the incremental cost of the nonstandard facilities. Lighting facilities that are customer-owned and customer-maintained are assigned to Rate Group D, while incidental lighting services (for example, underpass lighting) are assigned to Rate Group E. Customers in Rate Groups A and C pay a fixed monthly charge per lighting fixture, while customers in Rate Groups D and E pay a fixed (and identical) energy charge per kWh. Each customer's monthly bill also includes charges for ETI's fixed fuel factor (Schedule FF) and applicable riders applied to monthly kWh per fixture. Under Schedule TSS, traffic signal customers are subject to a minimum monthly charge ($3.20 proposed) per point of delivery, plus a fixed kWh rate and all applicable rider charges.[939]

Cities request that the Commission require ETI to institute a discounted lighting rate for Light Emitting Diode (LED) installations. Mr. Goins testified that the basic structure and pricing provisions of the SHL and TSS rates were designed for lighting fixtures that use older, less energy-efficient bulb technology, and ETI did not conduct any analyses to estimate the cost differential of serving street lighting and traffic signal customers that use energy-efficient LED

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939 Cities Ex. 4 (Goins Direct) at 22-23.

fixtures. In fact, Dr. Goins noted that the basic structure and pricing provisions of the SHL and TSS rates have been place for years.[940]

In Dr. Goins' opinion, adoption of LED lighting rates would help reduce energy consumption in Texas because such rates help offset the high front-end cost of LED lights and encourage municipalities to adopt energy-efficient LED options. In 2010, the Commission approved a street and traffic signal rate for El Paso Electric Company that included separate charges for LED traffic signals.[941] In that case, the fixed monthly rate for LED signals was generally less than one-third the comparable rate for incandescent signals.

Dr. Goins recommended that the Commission require ETI to modify monthly fixed charges in Schedule SHL (Rate Groups A and C) and the monthly minimum charge in Schedule TSS to reflect a 25 percent discount for LED installations. Under his proposal, the discounted Rate Group A fixed charges (if applicable) in Schedule SHL would be applied according to the estimated monthly kWh consumption of the installed LED fixture. In addition, he recommended reducing by 25 percent the Schedule SHL kWh charges applicable to LED customers assigned to Rate Groups D and E to reflect the lower cost of operating and maintaining LED fixtures. And he added that, in the future, ETI should be required to provide detailed information regarding differences in the cost of serving LED and non-LED lighting customers.[942]

Dr. Goins also requested that the Commission require ETI to eliminate the service condition applicable to Rate Groups A and C in Schedule SHL that charges a $50 fee for any replacement of a functioning light with a lower-wattage bulb. He stated that this fee actively discourages customers from adopting more energy-efficient lighting technologies (for example, LED devices), and was not

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[940] *Id.* at 23.

[941] *Application of El Paso Electric Company to Change Rates, to Reconcile Fuel Costs, to Establish Formula-Based Fuel Factors, and to Establish an Energy Efficiency Cost Recovery Factor*, Docket No. 37690 (July 30, 2010).

[942] Cities Ex. 4 (Goins Direct) 22-26.

supported in ETI's filing. In Dr. Goins' view, this barrier to conservation and efficiency improvements should be eliminated.[943]

Staff disagrees with Cities' request that ETI institute a discounted lighting rate for LED installations. Mr. Abbott testified that Cities did not provide empirical cost data to support this request. Without data on which to base an LED installation discount, he recommended that the Commission not require ETI to provide such a discount at this time. However, because of the growing use of LED installations and the potential cost savings to be realized from these installations, Mr. Abbott did recommend that the Commission require ETI to perform a cost study to determine appropriate cost-based rates for LED installations. This cost study could be used to develop LED lighting rates, which Mr. Abbott recommended ETI be required to submit as part of its next base-rate case.[944]

ETI is willing to perform a study to determine the feasibility of implementing LED lighting rates as part of its next base rate case filing. ETI witness Talkington explained that the Company does not currently offer ETI-owned LED lights but may do so in the future. She stated that if a customer wishes to use LED technology, it can install LE fixtures and receive service under Schedule SHL, Rate Groups D and E, or the existing Schedule TSS.[945]

Ms. Talkington took issue with Dr. Goins' proposed 25 percent decrease in Schedule SHL (Rate Groups A and C) and Schedule TSS for an LED option because the 25 percent rate reduction was not calculated. Thus, ETI prefers that it propose rates after a cost study. Ms. Talkington also disagreed with Dr. Goins' proposal for a 25 percent decrease in the energy-only options under Schedule SHL, Rate Groups D and E or Schedule TSS for customer-owned lights. She believes that a customer will have the benefit of more efficient LED lights by the reduction in energy consumed.[946]

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[943] *Id.*

[944] Staff Ex. 7 (Abbott Direct) at 28.

[945] ETI Ex. 67 (Talkington Rebuttal) at 17.

[946] *Id.* at 17-18.

The ALJs find persuasive Dr. Goins' testimony that: (1) the cost of street and traffic lighting services can be significant for many cities and towns; (2) government agencies face increasing pressure to control budgets and energy-efficient lighting is a good option; (3) LED fixtures use significantly less energy than incandescent and most other light options, last longer, and may require less maintenance; and (4) LED lighting rates would encourage municipalities to adopt energy-efficient LED options and help offset the high front-end cost of LED lights.[947] However, the ALJs concur with ETI and Staff that ETI should be directed to perform a LED lighting cost study before extensive changes are made to its lighting rates. The ALJs further recommend that ETI conduct this study before filing its next rate case and provide the results of any completed study to Cities and interested parties as soon as practicable but no later than the filing of its next rate case, as requested by Cities. Further, the ALJs recommend that the study include detailed information regarding differences in the cost of serving LED and non-LED lighting customers, if ETI has LED lighting customers taking service at the time it conducts its study. Finally, the ALJs note that ETI did not dispute Dr. Goins' suggestion to eliminate the service condition for Rate Groups A and C in Schedule SHL that charges a $50 fee for any replacement of a functioning light with a lower-wattage bulb. As noted by Dr. Goins, this fee discourages customers from adopting more energy-efficient lighting (such as LED devises). The ALJs concur and recommend that ETI modify the applicable tariffs to eliminate this fee for any replacement of a functioning light with a lower-wattage bulb.

2. Demand Ratchet

Staff witness Abbott testified that a demand ratchet is a provision in a utility's tariff that allows it to bill a customer based upon on the greater of either demand by that customer in the current month, or some fixed percentage of the customer's demand occurring during previous months. The Commission approved a settlement in Docket No. 37744, ETI's last base rate case, in which, among other things, ETI agreed to eliminate all life-of-contract demand ratchets from its tariffs for new customers with the implementation of rates. ETI further agreed that, in its next rate

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[947] Cities Ex. 4 (Goins Direct) at 24-25.

case, it would eliminate the life-of-contract ratchet for existing customers.[948] The Docket No. 37744 stipulation stated:

> Life-of-Contract Demand Ratchet. The Signatories agree that the life-of-contract demand ratchet provision in Rate Schedules Large Industrial Power Service [LIPS], Large Industrial Power Service-Time of Day [LIPS-TOD], General Service [GS], General Service-Time of Day [GS-TOD], Large General Service [LGS], and Large General Service-Time of Day [LGS-TOD] shall be excluded from the rate schedules in ETI's next rate case. The Signatories further stipulate that the foregoing rate schedules will be revised so that the life-of-contract demand ratchet provision shall not be applicable to new customers and, for existing customers, shall not exceed the level in effect on August 15, 2010.[949]

ETI then filed compliance tariffs in Docket No. 37744, which implemented the first part of the settlement by excluding new customers from its proposed life-of-contract demand ratchet. The following is the relevant sections from that compliance tariff, which is applicable to Large Industrial Power Service (LIPS) customers (all customers taking service under this tariff are required to enter into a service agreement contract with ETI):

> VI. DETERMINATION OF BILLING LOAD
> The kW of Billing Load will be the greatest of the following:
> (A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or
> (B) 75% of Contract Power as defined in § VII; or
> (C) **(1) For existing accounts with contracts for service for loads existing prior to August 15, 2010 – 60% of the Highest Contract Power established prior to August 15, 2010 as defined in § VII, (2) For new accounts with contracts for service for loads not existing prior to August 15, 2010 – Does Not Apply;** or
> (D) 2,500 kW.
>
> VII. DETERMINATION OF CONTRACT POWER
> Unless Company gives Customer written notice to the contrary, Contract

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[948] Staff Ex. 7 (Abbott Direct) at 16; *Application of Entergy Texas, Inc., for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744, Order at FOF 26(f) (Dec. 13, 2010). The ratchet is applicable to the General Service (GS), General Service – Time of Day (GS-TOD), Large General Service (LGS), Large General Service – Time of Day (LGS-TOD), Large Industrial Power Service (LIPS), and Large Industrial Power Service – Time of Day (LIPS-TOD).

[949] TIEC Ex. 27 (Docket No. 37744 Stipulation and Settlement Agreement) at 6.

Power will be as defined below:

Highest Contract Power – the greater of (i) the highest Billing Load established under the currently effective contract, or (ii) the kW specified in the currently effective contract.

Contract Power- the highest load established under § VI (A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, the Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.[950]

In this case, ETI changed the tariff provisions for all customers:

VI. DETERMINATION OF BILLING LOAD
The kW of Billing Load will be the greatest of the following:
(A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or
(B) 75% of Contract Power as defined in § VII; or
(C) 2,500 kW; or
(D) **60% of the kW specified in the currently effective contract.**

VII. DETERMINATION OF CONTRACT POWER
Unless Company gives Customer written notice to the contrary, Contract Power will be as defined below:

Contract Power shall be the highest load established under § VI(A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.[951]

The contested issue concerns ETI's new language. ETI maintains the new language is not a life-of-contract ratchet. Commission Staff, TIEC, and DOE disagree. Stated simply, Department of Energy (DOE) witness Dwight D. Etheridge testified that the introduction of the term "kW specified

950 TIEC Ex. 29 (Tariff Approved in Docket No. 37744)(emphasis added).

951 ETI 67 (Talkington Direct) at Ex. MLT-R-4 at 15 (emphasis added). ETI changed the relevant language in its tariff in its rebuttal testimony. Thus, the testimony of Messrs. Etheridge and Abbott can be slightly confusing because these witnesses address the tariff initially proposed by ETI.

in the currently effective contract" transforms what was a 12-month ratchet into a life-of-contract ratchet.[952]

At the outset, the ALJs note that some of ETI's proposed tariffs do comply with the stipulation in the prior case. ETI eliminated the life-of-contract provisions for the GS and GS-ToD customer classes. However, ETI's new language for the remaining ratchet classes, according to Staff witness Mr. Abbott, has the effect of maintaining a slightly different type of life-of-contract demand ratchet.[953] The discussion in this section applies to the LIPS class but the same argument follows for LGS and GS classes.

The parties contesting ETI's demand ratchet language argue that: (1) ETI's compliance tariff in Docket No. 37744 was consistent with the parties' agreement; (2) ETI's proposal imposes a life-of-contract demand ratchet; (3) the service agreement and tariff are linked; and (4) the new demand ratchet is not equitable or cost-based. These arguments are set out below.

- ***The agreed tariff from Docket No. 37744 was consistent with the parties' agreement and shows how LIPS billing load should be calculated.***

Staff, TIEC, and DOE agree that when ETI filed the compliance tariff in Docket No. 37744, the only demand ratchet that remained in the LIPS tariff for ETI's new customers was a 12-month demand ratchet. ETI removed the life-of-contract ratchet that set a perpetual obligation for a customer to pay for power based on its highest contract power or a percentage of its contract power. Staff, DOE, and TIEC argue that ETI's action in removing those provisions was consistent with the agreement and is evidence of what ETI should have done in this case. They contend that ETI witness Ms. Talkington agreed that the settlement eliminated *both* the highest load established under the currently effective contract *and* the amount specified in the contract.[954] In other words, the compliance tariff tracked the agreement.

[952] DOE Ex. 1 (Etheridge Direct) at 11.

[953] Staff Ex. 7 (Abbott Direct) at 16-19.

[954] Tr. at 1432.

ETI does not directly respond to this argument: Ms. Talkington did not address this in her rebuttal testimony. However, ETI states that the ALJs should "not be distracted by ETI's initial error of unintentionally removing the contracted capacity provision as to new customers in its compliance tariffs in Docket No. 37744."[955] Apparently, ETI believes that the tariffs it filed in compliance with the Docket No. 37744 agreement were in error.

➢ ***ETI proposes a demand ratchet in this case that is based on the contracted quantity stated in the tariff-required service agreement.***

All parties agree that what ETI proposes in this docket is different from the Docket No. 37744 tariff, as evidenced by Ms. Talkington:

> Q: So last time, when the company and the parties implemented the elimination of the life-of-contract ratchet, it eliminated the 60 percent ratchet applicable to both actual demand during the contract period or the contract – the amount specified in the contract.
>
> A. Yes, the way it's put in the schedule, yes.
>
> Q: And that's different than what you proposed in this case?
>
> A: *It is.*
>
> Q: And do you apply a different meaning to the agreement of what the life of contract ratchet meant than was applied in the tariff?
>
> A: Yes. What we have in this case is that the life-of-contract power relates to the highest load established under the currently effective contract . . .[956]

According to ETI, its proposed language does not impose life-of-contract ratchet, as defined by Mr. Pollock in Docket No. 37744 or by Messrs. Etheridge and Abbot in this case.

Witness	**Definition**

[955] ETI Reply Brief at 91.

[956] Tr. at 1432-1433 (emphasis added).

Witness	Definition
Pollock	"A life-of-contract ratchet is based on the highest demand ever imposed by a customer during the term of the contract." He further explained that ETI's proposed Docket No. 37744 tariff had "a life-of-contract ratchet [which] imposes a perpetual obligation to pay a minimum demand charge throughout the term of the contract."[957]
Etheridge	"A life-of-contract ratchet is a ratchet where you're not looking solely at current loads but some other loads in some prior period, so it creates a perpetual obligation to pay."[958]
Abbott	"[A] life of contract demand ratchet, which is based upon the highest demand established in the time period. . . . is one type of life-of-contact demand ratchet"[959]

ETI argues that the above definitions all make reference to the demand actually imposed by the operations of the customer's physical plant. But the contracted quantity provision it proposes is a minimum kW amount *contractually agreed* between the two parties to the service agreement, which is a required contract between the customer and ETI.[960] ETI argues the provision is not set by actual events during the term of the contract or in a prior period of the term of the contract, or in a monthly or 30-minute time period within the term of the contract; rather, it is set in the contract:

> That contracted quantity is set as, to use Mr. Etheridge's words, "an estimate" that cannot be unilaterally changed by the Company; instead, a change to that kW amount could only be made through negotiation between the two parties or through a proceeding before the Commission. To use Mr. Pollock's definition, it is not a demand "imposed by the customer during the term of the contract." It is instead a fixed, contractually agreed to amount that is set as a condition of service prior to the contract term.[961]

In sum, ETI argues the provision in question are not life-of-contract ratchets that lock the customer into the highest demand ever imposed by the customer's actual load during the term of the

[957] DOE Ex. 3 (Docket No. 37744 testimony excerpt) at 5-6.

[958] Tr. at 2004.

[959] Tr. at 1817.

[960] Mr. Etheridge testified that customers taking service under Schedule LIPS must sign a contract for service. Tr. at 1991.

[961] ETI Initial Brief at 211 (footnotes omitted), *citing* Tr. at 1994, 2012.

contract. Rather, they are, at most, 12-month ratchets that set the billing demand over a 12-month period, but not the life of the contract, at 75 percent.

Staff suggests that the Commission does not, fortunately, have to determine what contract provision may or may not constitute a life-of-contract demand ratchet. Rather, the Commission must ensure that ETI fulfilled its obligations under the Docket No. 37744 settlement. Staff believes that the parties to that settlement understood the meaning of the life-of-contract term, ETI followed through with compliance tariffs that evidenced its understanding, and now ETI should be required to stick with its agreement.

- ***The service agreement and tariff are linked.***

According to TIEC, ETI tries to make the argument that its proposal is justified because ETI and its large customers may sign an agreement for service that specifies a customer's contract power. This does not justify ETI's proposal because ETI's form "Agreement for Electric Service" expressly states that the agreement is subject to the terms of "applicable rate schedules."[962] Thus, maintains TIEC, the LIPS tariff billing load provisions impact a customer's contract power and can reasonably reduce a customer's billing load below its contract power if the customer has a reduction in load lasting longer than 12 months.

ETI's proposal should be rejected, argues TIEC, because it would allow the utility to indefinitely seek revenue from a customer that has nothing to do with the customer's actual usage or the utility's costs. For example, if a plant took 150 MW of load in its heyday, under ETI's proposal, the plant would be obligated to pay demand charges based on 60 percent of its original contract power. This is because ETI's standard agreement requires the utility's "express approval" to set a new contract power and the utility therefore could choose not to negotiate (or negotiate in a timely manner) a new contract power.[963] If LIPS billing load is tied to contract power, then its customers would be completely at its mercy to negotiate a reasonable contract power based on the customer's

[962] ETI Ex. 3, Schedule Q 8.8 at 11.1.

[963] ETI Ex. 3, Schedule Q 8.8 at 11.2.

actual usage for the time period. TIEC contends this is a ridiculous result and would render the parties' agreement to eliminate the life-of-contract ratchet meaningless.

➢ ***ETI's new demand ratchet is not equitable or cost-based.***

TIEC does not dispute that a 12-month ratchet is reasonable. However, Mr. Pollock, in Docket No. 37744, explained why a perpetual obligation to pay demand costs for load that the utility does not serve is objectionable:

> While it is appropriate to require customers to pay for the facilities they use, a perpetual obligation is both extreme and unnecessary. Typical demand ratchets reach back twelve months. A life-of-contract ratchet can reach back decades. This is particularly inappropriate when longstanding customers have permanently reduced operations. A customer that has reduced operations is not purchasing the same level of generation and transmission services as in the past, nor is ETI procuring the same level of generation and transmission services for the customer. Further, because of load growth on the ETI system, the capacity no longer being used by the customer would be used by other customers. Thus, a life-of-contract ratchet does not properly reflect cost-causation.[964]

➢ ***Witness Recommendations.***

Staff witness Mr. Abbott recommended that ETI be required to eliminate from its LGS, LGS-ToD, LIPS, and LIP-ToD tariffs the language that results in a ratchet based upon the current effective contract-specific demand. Also, if the Commission approves Mr. Abbott's recommendation, he stated that the billing determinants used to calculate the rates for the affected customer classes will likely change. Therefore, ETI should be required to update the affected billing determinants and reflect the resulting change in its rates in the compliance filing of this docket.[965]

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[964] DOE Ex. 3.

[965] Staff Ex. 7 (Abbott Direct) at 20.

DOE witness Etheridge also recommends that same for the LIPS tariff. He specified language that will exclude the life-of-contract ratchet language and retain the existing rolling 12-month ratchet language in Schedule LIPS.[966] Specifically, he proposed the following:

> VI. DETERMINATION OF BILLING LOAD
> The kW of Billing Load will be the greatest of the following:
>
> (A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or
> (B) [60%] of Contract Power as defined in § VII; or
> (C) 2,500 kW.
>
> VII. DETERMINATION OF CONTRACT POWER
> Unless Company gives Customer written notice to the contrary, Contract Power will be as defined below:
>
> Contract Power- the highest load established under § VI (A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, the Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.

- ***ALJs Recommendation.***

The ALJs find that ETI violated its agreement with the signatories in Docket No. 37744: the tariff language proposed by ETI is a life-of-contract demand ratchet. ETI failed to explain how the compliance tariffs adopted in Docket No. 37744 were in error. ETI's argument that its new language is not a life-of-contract demand ratchet was unpersuasive. To justify its modification, ETI relied only on a portion of Mr. Pollock's Docket No. 37744 definition. Moreover, both Messrs. Abbott and Etheridge were unequivocal that ETI, contrary to its agreement in the previous rate case, is imposing a life-of-contract or perpetual obligation to pay. Finally, the weight of the evidence supports a finding that the demand ratchet ETI proposes in this case is not equitable or cost based. The ALJs recommend that ETI's proposed LIPS tariff be amended to include the language proposed by Mr. Etheridge. The ALJs concur with Mr. Etheridge that, with such language, ETI has a financial

[966] ETI can adopt similar language for its LGS, LGS-ToD, LIPS, and LIP-ToD tariffs.

incentive to negotiate the maximum possible contracted level of capacity, not the minimum, and the result is consistent with the Docket No. 37744 agreement.

3. Large Industrial Power Service (LIPS)

TIEC witness Pollock explained that Schedule LIPS recovers base rates through a seasonally adjusted demand charge (per kW) and a two-step non-fuel energy charge (per kWh). The demand charges are also adjusted (either up or down) to reflect the differences in costs by delivery voltage. ETI's existing LIPS schedule has no customer charge. In its initial filing, ETI removed all purchased power capacity costs from base rates and proposed recovering them through a PPR as a demand charge. When it did so, the proposed demand charges were increased, but the proposed non-fuel energy charges were substantially reduced. Following the Supplemental Preliminary Order, which removed the PPR from further consideration, ETI proposed to roll these costs back into base rates. The resulting rebundled demand and energy charges would increase by about the same percentage.[967]

Mr. Pollock testified that the proposed structure of Schedule LIPS does not track costs as derived in ETI's class cost-of-service study. Specifically, he complained: (1) there is no customer charge, despite the fact that the customer costs allocated to the LIPS class would translate into a monthly rate of over $6,000, and (2) the proposed non-fuel energy charges would recover a significant amount of demand related costs. According to Mr. Pollock, production/transmission demand-related costs are $8.47 per kW, and distribution costs add another $0.99 per kW, for a total of $9.46 per kW. The proposed LIPS demand charges are $7.07 per kW for transmission delivery and an additional $1.82 for distribution service, for a total of $8.89 per kW. Thus, in Mr. Pollock's opinion, the proposed demand charges (given ETI's requested rate increase) are too low. By contrast, he noted, non-fuel energy costs are about 0.226¢ per kWh, while the proposed non-fuel energy charges would average over 0.600¢. Thus, these charges are 2.5 times higher than the non-fuel energy costs based on ETI's filing.[968]

[967] TIEC Ex. 1 (Pollock Direct) at 68-69.

[968] TIEC Ex. 1 (Pollock Direct) at 69-70.

(a) A New Customer Charge

TIEC urged that any increase in Schedule LIPS should be used to create a customer charge. Mr. Pollock calculated that a cost-based customer charge should be about $6,050 per month, and he recommended an initial customer charge of $6,000 per month. This would collect approximately $5.9 million ($6,000 x 984 bills). He added that any remaining increase not accounted for by the initial customer charge should be collected in the demand charges. He also stated that the non-fuel energy charges should not be changed unless the LIPS class is allocated less than a $5.9 million increase. In that event, he recommended that the non-fuel energy charges should be decreased. This would gradually correct the imbalance between the below-cost demand charges and above-cost energy charges. Mr. Pollock further stated that the delivery voltage adjustment applicable to distribution service should be retained so that the rate better reflects the cost. Should the LIPS class not receive an increase or if base rates are decreased, Mr. Pollock recommended that the customer charge should be reduced proportionally. Any remaining revenue surplus should be applied to reduce the non-fuel energy charges to cost and then to reduce the demand charges.[969]

Staff witness Abbott also recommends the introduction of a customer charge, but a much smaller one than that recommended by Mr. Pollock – $630.[970]

DOE supports Staff's proposed $630 customer charge. DOE witness Etheridge testified that TIEC's proposed $6,000 customer charge far exceeds a reasonable initial customer charge for Schedule LIPS. For example, the existing Commission-approved monthly customer charge for Schedule LGS is $425.05. Mr. Etheridge stated that the introduction of a $6,000 customer charge will lead to large shifts in intra-class revenue responsibility from high load factor customers to low load factor customers because a customer charge does not vary with usage. He noted, as an example, that TIEC's proposal would increase DOE's Big Hill annual costs by $72,000 or nearly 10 percent. Moreover, Mr. Etheridge pointed out that two parties are proposing to lower the Schedule LGS customer charge—approving either of these recommendations and TIEC's would levy Schedule LIPS customers with a new customer charge that is over 23 times the level of the LGS

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[969] *Id*. at 70.

[970] Staff Ex. 7 (Abbott Direct) at 27.

class. He believes such inconsistencies are inexplicable. Additionally, such disparity would present a challenge to any customer migrating from the LGS to the LIPS class.[971]

DOE witness Etheridge agreed that is appropriate to move toward cost-based rates, however, he indicated that gradualism should be properly applied to move rates toward cost without undue impact on low usage and low load factor customers in the LIPS class. If a new customer charge for the LIPS class is to be imposed—it should be that recommended by Commission Staff.[972]

The ALJs are persuaded by Mr. Etheridge's testimony that the adoption of a $6,000 customer charge far exceeds ETI's existing customer charge in the LGS Schedule and results in a significant and inappropriate impact to low load factor customers. Rather, Mr. Abbott's proposed customer charge of $630 is an appropriate charge to this customer class, particularly as ETI's current rates applicable to LIPS customers do not include any customer charge.[973]

(b) Demand and Energy Charges

In an effort to move more towards cost-based rates, Mr. Abbott recommends a slight decrease in the LIPS energy charges and an increase in the demand charges from current rates.[974] Mr. Pollock does not recommend an increase in energy charges. However, he recommends increasing demand charges to cover any remaining revenue increase for the LIPS class that is not accounted for with the customer charge. He suggested that such a change will gradually correct the imbalance between the below-cost demand charges and above-cost energy charges.[975]

DOE witness Etheridge expressed concerns with both proposals. He stated that Schedule LIPS customers are, on average, substantially more energy intensive than customers taking service under Schedule LIPS-TOD customers. He indicated that TIEC's proposed rate design (with

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[971] DOE Ex. 2 (Etheridge Cross-Rebuttal) at 3-4.

[972] DOE Ex. 2 (Etheridge Cross-Rebuttal) at 5.

[973] TIEC Ex. 1 (Pollock Direct) at 70.

[974] Staff Ex. 7 (Abbott Direct) at 27.

[975] TIEC Ex. 1 (Pollock Direct) at 70.

the $6,000 customer charge) would double the cost increase associated with base rates and the fuel factor for LIPS-TOD customers compared with the average cost increase for the class as a whole. Customers with lower load factors than Schedule LIPS-TOD customers would fare even worse.[976]

Mr. Etheridge also was concerned about Staff's proposed charges, noting that Mr. Abbott failed to explain how the slight decrease in the LIPS energy charge and the large increase in the demand charge would affect customers with changes in the revenue requirement ultimately assigned to the class. Mr. Etheridge stated that even Staff's proposed changes will noticeably shift intra-class cost responsibility toward Schedule LIPS customers with relatively low load factors. To address his concern that changes in the revenue requirement may have a significant impact even with Staff's gradual movement in rates, Mr. Etheridge recommended that Staff's proposal should set the limit on intra-class cost responsibility shifts.[977]

The ALJs find evidentiary support for and recommend the adoption of Mr. Abbott's proposed changes to Schedule LIPS. There is sufficient evidence, based on Mr. Pollock's testimony, that Mr. Abbott's suggested changes gradually move the rates towards cost without the risk of rate shock. TIEC's demand and energy proposals result in unreasonable large shifts in intra-class revenue responsibility. However, the ALJs also agree with Mr. Etheridge that Staff's proposal may need to be adjusted depending on the ultimate revenue requirement adopted.

4. Schedulable Intermittent Pumping Service (SIPS)

DOE proposes that a new rider, Schedulable Intermittent Pumping Service (SIPS), be included in the LIPS tariff. This will allow DOE and other customers with intermittent pumping loads to avoid application of a demand ratchet to schedulable, temporary, increased demand during off-peak months when ETI's costs are lowest. DOE suggests that the proposed rider will allow the DOE to schedule important testing and oil exchanges, when possible, during off-peak months, is consistent with existing riders, and does not adversely impact other customers.

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[976] DOE Ex. 2 (Etheridge Cross-Rebuttal) at 5.

[977] DOE Ex. 2 (Etheridge Cross-Rebuttal) at 5.

DOE explained that its Strategic Petroleum Reserve (Reserve) Texas sites—Big Hill in Jefferson County and Bryan Mound in Brazoria County—play an important role in ensuring the energy security of the United States. With a crude oil inventory of about 726.5 million barrels in 2010, the Reserve is the largest emergency supply of oil in the world. The Reserve was established by Congress as a result of the oil supply disruption in the early 1970s.[978]

DOE witness Etheridge testified that DOE takes service to its Big Hill site under Schedule LIPS at an annual cost of approximately $770,000. Mr. Etheridge explained that the Reserve's sites typically operate in standby mode, with routine cyclical tests of pumping equipment. The largest of these tests is performed every other year. These cyclical equipment tests can be coordinated with ETI so that they occur during low peak periods.[979]

On rare occasions, the Reserve can also be tapped. In its nearly 35 years of operations, there have been three Presidential-ordered drawdowns: January 1991, the beginning of Desert Storm; September 2005, Hurricane Katrina; and July-August 2011, the International Energy Agency coordinated release. The latter was the largest of the three drawdowns at 30.6 million barrels. Additionally, the Reserve has provided support to the oil industry in localized emergency or operational situations involving a disruption in supply, such as ship channel closures and hurricanes. When oil is exchanged during these situations, the Reserve will operate pumps at higher levels than would occur during normal standby operations.[980]

Mr. Etheridge proposed a rider to Schedule LIPS where maximum demands during pre-scheduled, non-summer month operations of a limited duration are not subject to demand ratchets. For this new rider, he proposed that the non-summer months be classified as October through May to give customers and ETI more flexibility. (Under Schedule LIPS, non-summer months are November through April.) Key provisions of the proposed SIPS rider include:

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978 DOE Ex. 1 (Etheridge Direct) at 3.

979 DOE Ex. 1 (Etheridge Direct) at 3-4

980 DOE Ex. 1 (Etheridge Direct) at 3-4.

- A requirement that customers schedule with ETI limited duration operations during non-summer months four weeks in advance.

- ETI must approve scheduled operations.

- Operations would not be allowed to exceed 10,000 kW in magnitude nor last for more than 80 hours per year.

- ETI could cancel operations at any time if a capacity constraint develops. If a customer failed to comply, the customer would incur costs associated with ETI's ratchet.

- A customer in compliance would not be subject to ETI's demand ratchets for loads established during those operations, but would pay the demand charge in the month in which the operations occur.[981]

Mr. Etheridge gave an example of charges under Schedule LIPS versus charges if the rider were adopted. In September 2010, Big Hill conducted a test and established a maximum measured demand of 11,640 kW, well above the site's average maximum demand of approximately 3,000 kW. DOE paid demand charges on the 11,640 kW in September 2010. In October 2010, ETI billed DOE for 75 percent of that level of demand or 8,730 kW based on the rolling 12-month ratchet. Its actual demand was 2,520 kW. In terms of actual costs, DOE paid $683,000 for its September usage. Under the 75 percent ratchet, DOE would pay $609,000 per month. Mr. Etheridge estimated that the charges amounted to $59/kW per year, which could easily represent nearly one-half of the annual carrying cost of a combustion turbine. Whereas, under the proposed rider, if DOE conducted the test in February as it intended to, it would have paid ETI for the 11,640 kW level of demand, but the usage would not be used in conjunction with ETI's ratchets. Mr. Etheridge concluded ETI's tariff is not equitable. At the hearing, Mr. Etheridge estimated that the rider's impact on other customer classes at approximately $500,000, where Schedule LIPS base rate revenues are approximately $110 million.[982]

According to DOE, for 15 years, June 1996-June 2011, ETI, by contract, accommodated the Reserve's intermittent load by allowing the DOE to, once annually, "reset" the demand level to be

[981] DOE Ex. 1 (Etheridge Direct) at 18.

[982] DOE Ex. 1 (Etheridge Direct) at 19-20; Tr. at 2034.

used by ETI when applying demand ratchets. The DOE was able to avoid significant demand charges when typical demand was very low. After June 2011, ETI declined to apply the terms of the long-time contract and allow the reset. DOE concedes that cost-based rates to reflect the Reserve's unique operations should ultimately be addressed by contract and/or new tariffs.

DOE notes that the very purpose of some riders is to address specific customer characteristics. For instance, Standby and Maintenance Service is available only to those customers that co-generate electricity; the Optional Rider to Schedule LIPS for Pipeline Pumping Service alters the designation of on peak-hours only for customers with pipeline pumping stations. Other riders, claims DOE, seek a win-win for all customers. For instance, the Rider to LIPS for Planned Maintenance rewards customers for scheduling routine maintenance and idling facilities during ETI's peak summer months of June through September by waiving the demand ratchet. DOE argues that the proposed SIPS rider mirrors Planned Maintenance by waiving the demand ratchet if customers are able to schedule intermittent loads outside of ETI's peak summer months. Moving toward cost-based rates is not discriminatory, claims DOE. Nor is rewarding customers who use their load scheduling flexibility for the benefit of all customers.

DOE's proposed SIPS rider is opposed by ETI, TIEC, and Staff.

ETI witness Talkington testified that the actual Reserve load, as Mr. Etheridge described, does not appear to match the parameters of his proposed SIPS rider. As recently as July and August 2011, the Reserve sites had significant load requirements in order to pump vast quantities of oil. She further testified that the Reserve loads are random in occurrence and are significant. ETI must at all times maintain generation resources to meet this significant and randomly occurring load. In addition, the Company has invested in transmission and other facilities to serve this customer even if there is no or very little consumption. She believed it would not be appropriate or equitable to other customers to remove or forgive the 12-month ratchet provision after the Company made these investments to serve the Reserve and while the Company has maintained generation to meet its load.

If the 12-month ratchet were forgiven, then the costs incurred to serve DOE would have to be borne by other customers in the LIPS rate class.[983]

TIEC witness Pollock complained that Mr. Ethridge failed to analyze the impact on other LIPS customers. Mr. Pollock contended the rider would discriminate against both Schedule LIPS customers (by redefining the summer billing period) and Schedule SMS customers (whose ability to schedule maintenance power could be subordinate to LIPS customer taking advantage of the new Rider).[984]

Staff is concerned that the rider's unusual eligibility requirements—that a customer must schedule load four weeks in advance, limit the high load occurrence to "off-peak months" (which is redefined in the rider), and limit the yearly hours of load—indicate it is tailored solely to meet the unique needs of the Reserve. According to Staff, DOE conceded that, although other customers with intermittent loads might take advantage of the proposed SIPS rider, Mr. Etheridge was not aware of any other actual customer that could do so.[985] Staff argues the rider appears to offer unreasonably preferential treatment to the DOE and should be rejected.

Beyond issues of discrimination, Staff is also concerned that the rider would shift costs from the DOE to other LIPS customers. Although DOE indicates that any shift would have a small overall impact on the LIPS class, Staff argues that the Commission should not endorse any discriminatory rate rider.

Although Staff and TIEC claim the proposed rider is discriminatory, other riders applicable to Schedule LIPS customers are available at different times of the year as well (Planned Maintenance is available only during the months of June through September) and others are limited to customer-specific needs—such as PPS for pipeline customers. Mr. Etheridge testified that this rider

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[983] ETI Ex. 67 (Talkington Rebuttal) at 41.

[984] TIEC Ex. 3 (Pollock Cross Rebuttal) at 9-10, 44-46.

[985] Tr. at 2008 ("Q: Now, who else would take advantage of this SIPS rate schedule, other than DOE? A: It's written such that any other customer that would have an intermittent schedulable load could take advantage of it. But I'm not sure if there are other customers on Entergy's system that could take advantage of it. Q: So you don't know that there are others who could use it. This could apply just to DOE? A: It could.").

could apply to any customer—it is not restricted solely to the DOE. The ALJs do not find this rider to be unreasonably discriminatory. As to ETI's concern on this issue, it was focused on whether the DOE's load met the proposed rider's requirements. However, if a customer taking service under the rider is unable to schedule its maintenance and oil exchanges with ETI, then the usage would be under the SIPS Schedule and the SIPS tariffed demand ratchet would apply. Moreover, Mr. Etheridge testified that the impact on other customer classes is limited. As to ETI's cost recovery, the LIPS rider customers will pay a demand charge to cover the costs they impose on the system in the month SIPS service is taken. The ALJs agree with DOE that the SIPS rider is reasonable and should be adopted.

5. Standby Maintenance Service (SMS)

TIEC witness Pollock explained that Schedule SMS applies to customers that use self-generation to supply a portion of their electricity requirements. These customers contract with ETI for either standby and/or maintenance power service to replace capacity or energy normally generated by the customer's on-site generation. Standby (or backup) power is electric energy or capacity supplied to replace energy or capacity that is unavailable due to an unscheduled or forced outage of the facility. Thus, backup power must be available at any time. Maintenance power is electric energy or capacity supplied during a scheduled outage. Unlike backup power, maintenance power must be arranged with 24-hour notice and only during such times and at such locations that, in ETI's opinion, will not result in adversely affecting or jeopardizing firm service to other customers, prior commitments, or commitments to other utilities. In addition, the customer must make arrangements and schedule maintenance power in writing in advance and confirmed in writing by ETI. ETI can also limit requests for maintenance power and allocate and schedule available service, if requests are made from more than one customer. Thus, Mr. Pollock stated that maintenance power is of a lower quality of service than backup or standby power. He also indicated that, because the Company can limit the amount of maintenance power, it is more likely that customers would prefer to schedule maintenance power during the non-summer months.[986]

[986] TIEC Ex. 1 (Pollock Direct) at 70-71.

ETI witness Talkington explained that standby service includes both the readiness to serve and the actual delivery of power and energy delivered when a customer requires service due to a forced outage or a planned maintenance period. She indicated that many utilities offer a combination of pricing and terms for demand and energy service as well as a form of reservation charge dealing with the readiness to serve. She further indicated that the actual rate design may differ, but standby tariffs usually contain provisions for back-up (forced outage) or maintenance (planned outage). She concluded that ETI's current rate schedule provides for these features, and ETI is not proposing to change Schedule SMS in this proceeding.[987]

TIEC proposes to redesign SMS service to better reflect the cost characteristics of standby and maintenance power customers. Mr. Pollock provided his analysis to support TIEC's position. Under the current Schedule SMS, customers pay a monthly demand (or billing load) charge of $1.12 per kW for backup power. The corresponding charges for maintenance power are $1.12 per kW for outages during the summer months (May through October) and $0.84 per kW for outages during the non-summer months. Thus, the non-summer month charge is 75 percent of the summer month charge. Energy is priced under an array of time-differentiated charges, as shown in the table below:[988]

Current Schedule SMS Non-Fuel Energy Charges (¢ per kWh)		
Delivery Voltage	On-Peak[989]	Off-Peak
Distribution (less than 69KV)	3.386¢	0.514¢
Transmission (69KV and greater)	2.334¢	0.211¢

Mr. Pollock examined P.U.C. SUBST. R. 25.242(k)(1) and concluded that, for Standby Service, cost-based standby rates should recognize system-wide costing principles and must not be discriminatory. According to his analysis, the SMS demand charges should be $0.82 per kW for

[987] ETI Ex. 67 (Talkington Rebuttal) at 19-20.

[988] TIEC Ex. 1 (Pollock Direct) at 72-73.

[989] On-peak hours are from 1:00 p.m. to 9:00 p.m., Monday through Friday of each week, beginning on May 15 and continuing through October 15. In addition, fuel charges are priced at avoided energy cost as calculated under Schedule LQF. TIEC Ex. 1 (Pollock Direct) at 72.

delivery at transmission and $2.64 per kW for delivery at distribution. He also determined that cost-based energy charges should be as follows:[990]

Cost-Based Schedule SMS Non-Fuel Energy Charges (¢ per kWh)		
Delivery Voltage	On-Peak	Off-Peak
Distribution (less than 69KV)	0.955¢	0.639¢
Transmission (69KV and greater)	0.916¢	0.614¢

Mr. Pollock explained that, on average, 7 percent of Schedule SMS billing demand was coincident with ETI's summer month system peaks. This compares to 74 percent for Schedule LIPS; thus, the ratio of the SMS to LIPS coincidence factors is 12 percent. By Mr. Pollock's calculations, the resulting demand charge for transmission service would be $0.82 per kW ($7.07 x 12 percent), and the corresponding SMS distribution demand charge would be the sum of the transmission charge and the Schedule LIPS distribution demand charge, or $2.64 per kW ($0.82 + $1.82).[991]

Mr. Pollock testified that he combined production and transmission costs in deriving a cost-based schedule SMS demand charge for transmission delivery, because both production and transmission demand-related costs are allocated to customer classes using the A&E 4CP method. This method recognizes that production/transmission plant is sized to meet the diversified summer peak demands of all ETI customers. That is, Mr. Pollock stated, the 4CP demands are a primary driver of the costs of the power plants, PPAs, and transmission facilities. As noted above, Mr. Pollock contended and verified by analysis that a cost-based Schedule SMS demand charge should be only 12 percent of the corresponding demand charge for Schedule LIPS.[992]

Mr. Pollock also stated that he proposed to differentiate the standby demand charge by delivery voltage because it more directly recognizes the different costs to provide service at

[990] TIEC Ex. 1 (Pollock Direct) at 73-74 and Ex. JP-15.

[991] *Id.* at 72-74.

[992] *Id.* at 75-77.

transmission and distribution voltage. He added that this recommendation is consistent with the current Schedule SMS energy charges.[993] However, Mr. Pollock did not apply the 12 percent coincidence ratio to determine the distribution-related schedule SMS demand charge. He explained that distribution facilities are electrically closer to customers, so a customer's peak demand determines how distribution facilities must be sized to ensure reliable service. He stated that ETI recognized this driver by using maximum diversified demand to allocate distribution demand-related costs. For this reason, Schedule SMS customers require the same amount of distribution capacity as a similarly sized Schedule LIPS customer. Thus, according to Mr. Pollock, the Schedule SMS distribution demand charge should be the same as the corresponding Schedule LIPS demand charge.[994]

Concerning energy charges, Mr. Pollock testified that the Schedule SMS energy charge should reflect the composite Schedule LIPS energy charges, or 0.614¢ per kWh. In his view, a Schedule SMS customer should also pay additional demand charges during on-peak hours, because this would recognize that an SMS customer that purchases more energy during on-peak hours would more closely resemble a LIPS customer. For this reason, cost-based on-peak energy charge should be a composite of the Schedule LIPS energy charge and the remaining demand charges (not collected in the SMS demand charge). He calculated an additional on-peak energy charge of 0.303¢, which yields a total on-peak energy charge of 0.917¢. Under this structure, an SMS customer that experiences an outage would pay approximately the same for electricity as a LIPS customer.[995]

In summary, Mr. Pollock contended that Schedule SMS should be reduced to more closely reflect the cost of providing standby service as follows:[996]

Cost-Based Schedule SMS Charges Based on ETI's Proposed Schedule LIPS Design		
Charge	Distribution (less than 69kV)	Transmission (69kV and greater)

993 TIEC Ex. 1 (Pollock Direct) at 77.

994 *Id*. at 77-78.

995 *Id*. at 77-78; Ex. JP-15.

996 *Id*. at 79.

Billing Load Charge ($/kW)		
Standby	$2.64	$0.82
Maintenance	$2.44	$0.62
Non-Fuel Energy Charge (¢/kWh)		
On-Peak	0.955¢	0.916¢
Off-Peak	0.639¢	0.614¢

Using his recommended Schedule LIPS rate design, he proposed Schedule SMS charges shown in the table below:[997]

TIEC Proposed SMS Charges		
Charge	Distribution (less than 69kV)	Transmission (69kV and greater)
Customer Charge (Stand Alone)	$6,000	
Billing Load Charge ($/kW)		
Standby	$2.46	$0.79
Maintenance	$2.27	$0.60
Non-Fuel Energy Charge (¢/kWh)		
On-Peak	0.881¢	0.846¢
Off-Peak	0.575¢	0.552¢

Mr. Pollock based his recommended charges on ETI's proposed revenue requirements and class revenue allocation. If the Schedule LIPS revenue requirement is reduced, the charges should be correspondingly reduced. Mr. Pollock also added a customer charge, but he stated that the customer charge should not apply if a Schedule SMS customer also purchased supplementary power under another applicable rate.[998]

To determine maintenance power charges, Mr. Pollock maintained the same relationship; that is, the current maintenance power demand charge is 75 percent of the standby power demand charge. He stated that the 75 percent should apply to the production/transmission component of the recommended standby power demand charge because distribution costs are caused by maximum demands occurring at any time, as previously discussed. This would result in a $0.20 and

[997] TIEC Ex. 1 (Pollock Direct) at 80.

[998] *Id*. at 79.

$0.19 per kW differential based on ETI's proposed and Mr. Pollock's recommended Schedule LIPS designs, respectively.[999]

The ALJs note that Mr. Pollock's suggested changes to Schedule SMS are extensive. For instance, he introduced a $6,000 customer charge and, for the monthly billing load (demand) charges, he introduced separate rates for distribution and transmission customers.[1000]

Ms. Talkington testified that Mr. Pollock erred in using load data for the period of 2007 through 2011 to develop a coincidence factor that he then uses to develop a lower back-up and maintenance demand charge for transmission-level customers, while significantly increasing the charge for distribution-level customers. She also stated that Mr. Pollock's proposal fails to recognize the "readiness to serve" aspect of standby service. ETI must be ready to serve the load represented by the largest generation unit taking standby service, plus account for the forced outage rates for all other existing customer-owned generators.[1001]

Ms. Talkington also stated Mr. Pollock failed to recognize that standby load does not lend itself to the typical rate design practices. She opined that the cost of providing SMS service is not driven only by the degree to which standby customers contribute to peak demand, but also by the Company's obligation to serve whenever called upon. This is the major reason Schedule SMS is not included in the development of allocation factors.[1002]

Ms. Talkington admitted that she is not familiar with how ETI originally developed Schedule SMS, but stated that she knows that when a customer takes back-up or maintenance service, costing is generally designed to mimic what the customer would have paid on standard rates,

[999] TIEC Ex. 1 (Pollock Direct) at 80.

[1000] TIEC Ex. 1 (Pollock Direct) at 80.

[1001] ETI Ex. 67 (Talkington Rebuttal) at 20-21.

[1002] ETI Ex. 67 (Talkington Rebuttal) at 21.

absent the use of its own generator. She concluded that Mr. Pollock's analysis is over-simplified and incomplete.[1003]

In rebuttal testimony, Ms. Talkington proposed a new rate design for SMS service, including a new service, Non-Reserved Service, which is an optional service designed to supplement Maintenance Service. ETI's new SMS proposal increases ETIs test year base rate revenues by 53.27 percent, with an overall increase of $5.1 million. ETI did not include this rate increase in its notice.[1004] Accordingly, the ALJs determine that ETI's new SMS proposal is not an option to be considered in this case.

Commission Staff does not oppose ETI's request to retain its current Schedule SMS.

ETI did not demonstrate how its current rates are just and reasonable. Rather, ETI's evidence on the reasonableness of Schedule SMS is conclusory and insufficient in light of Mr. Pollock's testimony that the rates are not cost-based. Moreover, although Ms. Talkington indicated her concern with Mr. Pollock's analysis, she provided no quantitative support for her concern. The ALJs, however, are concerned that Mr. Pollock's suggested changes are not accompanied by a rate impact analysis. And, as noted above, his suggested changes are extensive. Mr. Pollock's recommendations included a significant increase in the charge for distribution-level customers. Consistent with his Schedule LIPS recommendation, Mr. Pollock also included a $6,000 customer charge when no previous customer charge existed. Again, there is no analysis as to the effect such a charge would have on customer bills. The testimony of witnesses Benedict, Abbott, Higgins, and Pevoto caution that gradualism should be considered in rate design. As noted by Mr. Higgins, "full movement to cost-based rates in a single step is sometimes opposed on the grounds of intra-class rate impacts."[1005] However, the rate impact at this time is not known.

[1003] ETI Ex. 67 (Talkington Rebuttal) at 21-22.

[1004] PURA § 36.102 and P.U.C. PROC. R. 22.51 require a utility to publish notice of its intent to change rates, with proposed revisions of tariffs and a detailed statement of each proposed change, the effect it is expected to have on revenues, the class and number of customers affected by the change.

[1005] Kroger Ex. 1 (Higgins Direct) at 10.

Based on the evidence and discussion above, the ALJs recommend adoption of Mr. Pollock's suggested changes to Schedule SMS , with the exception of a $6,000 customer charge. Consistent with the ALJs' recommendation that a new LIPS charge of $630 is reasonable, the SMS charge should be limited to $630 and, as suggested by Mr. Pollock, not apply if a Schedule SMS customer also purchased supplementary power under another applicable rate.

6. Additional Facilities Charge (AFC)

Mr. Pollock testified that Schedule AFC is the mechanism for charging customers directly for the costs of transformers, breakers and lines when those facilities provide service only to specific customers. Some of these facilities are booked to transmission accounts while others are booked to distribution accounts. Schedule AFC is applied as a percentage of the original (un-depreciated) cost of the facilities.[1006]

TIEC contends that the Schedule AFC charges should be revised. According to Mr. Pollock, the current charges exceed ETI's ownership and O&M costs; therefore, he recommended that the monthly charges in Schedule AFC be reduced. Under this rate schedule, there are two separate pricing options. Option A charges 1.49 percent per month; Option B applies when a customer elects to amortize the direct assigned facilities over a shorter term, ranging from one to ten years. Thus, the Option B Monthly Recovery Term charge varies depending on the length of the amortization period of the directly assigned investment. A 0.453 percent Monthly Post-Recovery term charge also applies after a facility has been fully depreciated. ETI did not propose to change either the Option A or Option B charges in Schedule AFC.[1007]

According to Mr. Pollock's analysis, charges imposed under Option A should be 1.20 percent per month under ETI's proposed revenue requirements. Under Option B, Mr. Pollock proposes various changes to the Recovery Term charges, and reduces the Monthly Post-Recovery term to 0.35 percent per month. Further, if the Commission approves a lower base revenue requirement than ETI has proposed, Mr. Pollock stated that the recommended Schedule AFC charges (both Option A

[1006] TIEC Ex. 1 (Pollock Direct) at 81.

[1007] *Id.* at 82-85.

and Option B) should be reduced in proportion to any authorized reduction in ETI's proposed rate of return, O&M expense, and property tax expense.[1008]

In reaching this recommendation, Mr. Pollock used two different methods to derive a cost-based rate: a levelized cost analysis and a revenue requirement analysis. The former resulted in an Option A rate of 1.20 percent per month, and the revenue requirement analysis resulted in a weighted average rate of 1.18 percent. For Option B charges, Mr. Pollock also used a levelized cost analysis for each of the Option B amortization periods, which resulted in lower charges.[1009]

ETI witness Talkington disagrees with Mr. Pollock's description of Schedule AFC. She testified that the rate schedule encompasses the costs associated with the installation of facilities other than those normally furnished. Or, under one option, the rates are like a monthly rental charge paid for facilities that would not normally be supplied by the Company. She also stated that Mr. Pollock's example of facilities (transformers, breakers and lines) is understated.[1010]

ETI contends that revisions to this discretionary rate are unwarranted at this time. The Commission approved this rate structure (and rate) in Docket No. 16705. Moreover, ETI witness Talkington testified that this rate is voluntary—a customer has alternatives beyond those offered by ETI. Therefore, it is actually a market-driven rate. If a customer does not want to use this schedule to obtain the services it provides, the customer can secure services through other sources—either ETI-owned or otherwise. Ms. Talkington further stated that Mr. Pollock's suggested changes would be detrimental to the customers who do not have AFC rates because the AFC revenue is treated as an offset to the revenue requirement to the rate classes.[1011]

Staff does not oppose ETI's request to retain the AFC rate as it is currently designed.

[1008] TIEC Ex. 1 (Pollock Direct) at 81-85 and at Exs. JP-17 and JP-18. *See* ETI Ex. 3, Sch. Q-8-8 at 24.

[1009] TIEC Ex. 1 (Pollock Direct) at Ex. JP-18.

[1010] ETI Ex. 67 (Talkington Rebuttal) at 31.

[1011] ETI Ex. 67 (Talkington Direct) at 27-28.

The ALJs find insufficient support in the record to retain ETI's Schedule AFC as-is. As noted by TIEC, there is no evidence in this case to support ETI's claim that: (1) the rate is a voluntary rate; (2) there are other options in the market for customers; or (3) that the rate continues to be based on a cost that the market will bear (as the Commission found years ago in Docket No. 16705).[1012] While Ms. Talkington disagreed with Mr. Pollock's proposal because he did not take into consideration the scope of facilities provided and that his proposal could be detrimental to other ratepayers because ETI's revenues from this rate will decrease, she did not quantify her concerns.[1013] The evidence supports a change to Schedule AFC that will move the rate more towards costs, and TIEC's proposals are the only ones for which there is evidence in the record. The ALJs further agree with Mr. Pollock that his numbers should be reduced in proportion to any authorized reduction in ETI's proposed rate of return, O&M expense, and property tax expense.

7. Large General Service (LGS)

Kroger witness Kevin C. Higgins testified that the LGS rate schedule serves customers with monthly billing demands between 300 kW and 2,500 kW. ETI proposes to increase the LGS demand charge from $8.56 per kW-month to $10.25 per kW-month and to increase the energy charge from $.00854 per kWh to $.01023 per kWh. The Company proposes no change in the customer charge of $425.05 per month.[1014]

Mr. Higgins testified that ETI's proposed LGS demand charge would recover only 72 percent of LGS demand-related costs. To compensate for the resultant revenue shortfall, the LGS energy charges proposed by ETI would significantly over-recover energy-related costs. Specifically, the overall LGS energy charge is proposed to be 428 percent of base energy costs. In addition, although the customer charge is proposed to be unchanged, it is set at 328 percent of cost. If, instead, the LGS customer charge were set at cost, it would only be $129.60 per month.[1015]

1012 *See* Docket No. 16705, Final Order, FoFs 292-296.

1013 Tr. at 1437, 1439-1440.

1014 Kroger Ex. 1 (Higgins Direct) at 7.

1015 *Id.* at 8.

Mr. Higgins illustrated his findings in the table below:[1016]

LG Total Class Functionalized Cost Recovery				
Functions	Costs	Collected in Rates	(Under)/Over Collection	Percentage Recovered
Demand	$46,266,083	$33,116,674	$(13,149, 409)	71.6%
Energy	$3,6625,811	$15,556,253	$11,920,442	427.9%
Customer	$561,445	$1,841,316	$1,279,871	328.0%
Total	$50,463,339	$50,514,243	$50,904	

Mr. Higgins stated that if a utility proposes a demand charge that is below the cost, it is going to seek to recover its class revenue requirement by over-recovering its costs in another area, typically through an energy charge that is above unit energy costs. In his opinion, for LGS, when demand charges are set below costs and energy charges are set above cost, customers with relatively higher load factors are required to subsidize the costs of lower load factor customers within the rate class. The subsidy is different for each higher load factor customer (a customer whose load factor is greater than the average for the rate schedule) and consists of the net increase in rates paid by these customers as a result of setting energy charges above energy costs and demand charges below demand related costs. When the customer charge is set significantly above costs, smaller customers are overcharged and subsidize the larger customers.[1017]

Recognizing that a full movement towards cost-based rates (without gradualism) in a single step may create intra-class rate impacts, Mr. Higgins proposed the following changes to better align costs:[1018]

1016 Kroger Ex. 5.

1017 Kroger Ex. 1 (Higgins Direct) at 9.

1018 *Id.* at 10-11.

Functions	ETI Proposed Charge	% of Cost	Kroger Proposed Charge	% of Cost
Demand ($/kW)	$10.25	72%	$12.81	90%
Energy ($/kWh)	$0.01023	428%	$0.00513	216%
Customer ($/Mo)	$425.05	328%	$260.00	201%

Mr. Higgins developed his proposed rate impacts, which indicated a smaller rate impact on higher load factor customers than those with low load factors. He found them to be comparable to the rate impact found in ETI's proposed rates.[1019]

ETI witness Talkington did not object to gradually moving rates toward setting demand energy and customer components closer to cost of service in the LGS class.[1020]

Based on principles of cost-based rates and of gradualism, Staff witness Abbott recommended a decrease in the LGS customer charge to $397.02 from the current (and Company proposed) $425.05, and an increase in the energy charges, which is less than the increase proposed by the Company.[1021]

The ALJs found Mr. Higgins' proposed changes reasonable and well supported. Schedule LGS should be amended as proposed by Kroger. Schedule LGS also has a demand ratchet, and the ALJs' recommendation for the elimination of ETI's LIPS demand ratchet is applicable to this class.

[1019] *Id.* at 11, Ex. KCH-3.

[1020] Tr. at 1452.

[1021] Staff Ex. 7 (Abbott Direct) at 25-27.

8. General Service (GS)

Based on principles of cost-based rates and of gradualism, Staff witness Abbott recommended a decrease in the GS customer charge to $39.91 from the current (and Company proposed) rate of $41.09. Staff also recommended a decrease in the energy charges.[1022]

No party disputed Staff's recommendations, which the ALJs adopt. Schedule GS also has a demand ratchet, and the ALJs' recommendation for the elimination of ETI's LIPS demand ratchet is applicable to this class.

9. Residential Service (RS)

ETI's RS rate schedule is composed of two elements: a customer charge of $5 per month and a consumption-based energy charge. The Energy charge is a fixed rate of 5.802¢ per kWh from May through October (Summer). In the months November through April (Winter), the rates are structured as a declining block, in which the price of each unit is reduced after a defined level of usage. For instance, the same energy charge of 5.802¢ applies, but only for each of the first 1,000 kWh consumed. Each kWh consumed beyond 1,000 is billed at a lower rate of 3.834¢.[1023]

ETI proposes to retain the general structure of the RS rate design but proposes an increase in the dollar amount of each rate element. OPC witness Benedict noted ETI's proposed changes in his testimony, as set out below:[1024]

Rate Element	ETI Current	ETI Proposed	Percent Increase
Customer Charge (per month)	$5.00	$6.00	20.0%
Energy Charge (Summer, all kWh)	$0.05802	$0.07268	25.3%

[1022] *Id.*

[1023] OPC Ex. 6 (Benedict Direct) at 41, Ex. NAB-1, ETI's Response to State RFI No. 4-17; ETI Ex. 67 (Talkington Rebuttal) at 9.

[1024] OPC Ex. 6 (Benedict Direct) at 42.

Rate Element	ETI Current	ETI Proposed	Percent Increase
Energy Charge (Winter, kWh ≤ 1000)	$0.05802	$0.07268	25.3%
Energy Charge (Winter, kWh > 1000)	$0.03834	$0.04799	25.2%

OPC criticized ETI's declining block rate structure as being contrary to energy efficiency efforts. OPC witness Benedict noted that under ETI's proposed rate structure, once kWh usage exceeds 1,000 in a winter month, the per-kWh cost of consumption falls by 34 percent. Thus, because a declining block rate structure lowers the per-unit rate for high levels of consumption, heavy users are induced to consume more than they would otherwise. In his view, this runs contrary to the Legislature's goal of reducing both energy demand and energy consumption in Texas, as stated in PURA § 39.905:

> (a) It is the goal of the legislature that: . . . (2) all customers, in all customer classes, will have a choice of and access to energy efficiency alternatives and other choices from the market that allow each customer to reduce energy consumption, summer and winter peak, or energy costs.

Therefore, Mr. Benedict recommended that the declining block rate be phased out over time. He stated this would ease the transition to a rate structure without a declining block, and it would allow time for customers to switch to more efficient heating systems. Mr. Benedict proposed that the phase-out take place over three rate cases, beginning with a one-third reduction in the block differential proposed by ETI in this case. Reducing ETI's proposed block differential from 2.469¢ to 1.645¢ accomplishes the initial one-third reduction, as illustrated below (using ETI's requested revenue requirement):[1025]

Rate Element	ETI Current	ETI Proposed	Percent Increase	Reduced Block Rate Differential	Percent Increase
Customer Charge (per month)	$5.00	$6.00	20.0%	$6.00	20%

[1025] OPC Ex. 6 (Benedict Direct) at 43-45.

Energy Charge (Summer, all kWh)	$0.05802	$0.07268	25.3%	$0.07141	23.1%
Energy Charge (Winter, kWh ≤ 1000)	$0.05802	$0.07268	25.3%	$0.07141	23.1%
Energy Charge (Winter, kWh > 1000)	$0.03834	$0.04799	25.2%	$0.05496	43.3%

Mr. Benedict stated that his proposal related to an intra-class rate design issue and was not intended to affect the amount of revenue to be collected from the residential class or any other class. If, however, the Commission approves a different revenue requirement for the residential class to reflect various proposed adjustments, rates for the class will need to be recomputed regarding a reduced block differential[1026]

Staff generally agreed with OPC's recommendation for a reduction in the rate differential between the residential winter kWh ≤ 1000 block and the winter kWh > 1000 block, due to the inconsistency between the incentives produced under declining block rates and the State's energy efficiency goals. Staff witness Abbott stated that the extreme cold weather event of February 2011 demonstrated a need to incentivize wintertime energy efficiency measures, or at least a need to avoid encouraging excess energy usage. Therefore, Mr. Abbott agreed that some reduction in the rate block differential is warranted to better encourage wintertime energy conservation at the margin.[1027]

ETI witness Talkington testified that the RS rates are cost-based with a declining block rate in winter. According to Ms. Talkington, residential load factors in winter increase as energy usage increases, and there is also a decrease in the fixed unit cost ($/kWh) as energy usage increases. She provided analysis to support her position.[1028] Ms. Talkington explained that residential rates do not include demand charges because of the absence of residential demand meters. However, residential energy rates can be structured the same as the non-residential classes; that is, customer charge, demand charge and energy charge. She developed residential rates on this basis to show that the declining block rate is appropriate to account for reductions in the cost of service to residential

[1026] OPC Ex. 6 (Benedict Direct) at 46.

[1027] Staff Ex. 7 (Abbott Direct) at 27.

[1028] ETI Ex. 67 (Talkington Rebuttal) at 13, Ex. MLT-R-1.

customers as consumption increases. With no declining block rate, high load factor customers are disadvantaged as the customer charge is reduced and the demand charge is moved into the energy charge. She believes that declining block rates alleviate the disadvantage.[1029]

Ms. Talkington illustrated the impact of Mr. Benedict's suggestion to phase out the declining block rate for RS customers. Approximately 54 percent of ETI's residential customers use more than 1,000 kWh in January and February. For a customer using 3,000 kWh in a winter month of November-April, this customer's bill would increase by 16.28 percent or about $48 over current rates. (Of ETI's total number of RS customers, approximately 10 percent use 3,000 kWh or more in the months of January and February.) For that same customer, ETI's as-filed proposal shows an increase of 11.96 percent or approximately $35. Mr. Benedict's proposal is $13 greater than ETI's proposal for one winter month at 3,000 kWh. That dollar amount is over a third of the total increase ETI is proposing.[1030]

After Mr. Benedict's proposed phase-out is completed, based on the proposed residential rates in the Company's case, the residential rate would be $0.06887 per kWh in both summer and winter. A customer using 3,000 kWh in a winter month of November-April would see an increase of 24.89 percent or about $73 over current rates. After the final phase out, Mr. Benedict's proposal is $38 per month greater than ETI's as-filed proposal of $35 for one winter month at 3,000 kWh.[1031]

Ms. Talkington further noted that rate design professionals always take into consideration the effect on customer bills. Even though Mr. Benedict proposes to implement the change over the next three rate cases, she concludes there will still be winners and losers within the residential class as a result of his proposed change. According to Ms. Talkington, some customers have made decisions about investing in electric appliances based on the current rate design. The elimination of the declining block in the winter time changes the economics of customer decisions that have already been made. She believes that great caution needs to be exhibited and very good reasons need to be demonstrated before changes are made to the rate design. She recommended that if a change to the

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[1029] *Id*. at 14.

[1030] *Id*. at 15.

[1031] *Id*. at 15-16.

rate structure is recommended, the initial phase-in should be reduced to 10 percent rather than one-third and subsequent reductions should be reviewed for consideration at the occurrence of each rate case filing and not mandated at this time.[1032]

The ALJs concur with OPC and Staff that the structure of the declining block winter rates provide a disincentive to energy efficiency. However, ETI provided evidence that OPC's suggested changes, combined with ETI's proposed rate increase, will have too great an impact. OPC suggested a one-third reduction in the differential, while Ms. Talkington suggested a 10 percent reduction, with subsequent reductions reviewed before being mandated. The ALJs recommend an initial 20 percent reduction, which should alleviate some of ETI's concerns but still reduce the block differential sufficiently to move towards compliance with the energy goals set out in PURA. The ALJs further recommend that 20 percent subsequent reductions of the differential be required in the next three rate cases unless ETI provides sufficient evidence that such changes are unjust and unreasonable.

XI. FUEL RECONCILIATION [Germane to Preliminary Order Issue Nos. 21-31]

In the application, ETI seeks to reconcile approximately $1.3 billion in fuel and purchased power expenses incurred over the 24 month Reconciliation Period. Summaries of ETI's total fuel and purchased power expenses and over/under recovery balance are shown below.

[1032] ETI Ex. 67 (Talkington Rebuttal) at 15-17.

Fuel Reconciliation	
Gas and Oil	$616,248,686
Emissions Allowance	360,236
Coal	90,821,317
Total Fuel:	**$707,430,239**
Purchase Power Expense	990,041,434
Off-system Sales Revenues	(376,671,969)
Total Purchased Power:	**$613,369,465**
Total Fuel Costs:	**$1,321,799,704**
Over-recovery Balance:	**$243,339,353**
Special Circumstances	**$99,715**
Sources: ETI Ex. 3 Schedules I-16, H-12.4a-g, H-12.5b-e, I-21; ETI Ex. 11 (McCloskey Direct); ETI Ex. 23 (Zakrzewski Direct).	

ETI contends, and the evidence presented at the hearing demonstrates, that these fuel factor expenses were eligible for reconciliation and were reasonable and necessary to provide reliable service to ETI's customers during the Reconciliation Period. With the exception of three minor issues that are discussed below, none of the intervenors raised a substantive issue with respect to ETI's fuel reconciliation request.

During the Reconciliation Period, ETI's Texas fuel factor revenues over-recovered total fuel and purchased power expense by $243,339,353, inclusive of interest. The Commission authorized the refund of the fuel over-recovery balance in Docket Nos. 37580, 38403, and 38967. ETI proposes that the amount of any fuel over-recovery balance not already refunded or authorized for refund be rolled forward as the beginning balance for the next reconciliation period.[1033]

P.U.C. SUBST. R. 25.236(d)(1) states that in a fuel reconciliation proceeding, the utility has the burden of showing that:

(A) its eligible fuel expenses during the fuel reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers;

(B) if its eligible fuel expenses for the reconciliation period included an item or

[1033] ETI Ex. 40 (Thiry Direct) at 7.

class of items supplied by an affiliate of the electric utility, the prices charged by the supplying affiliate to the electric utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and

(C) it has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

In Docket No. 15102, an EGSI fuel reconciliation case, the Commission explained the traditional prudence standard to be applied in reviewing decisions made by the utility:

> The exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.
>
> There may be more than one prudent option within the range available to a utility in any given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility . . . . The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.[1034]

ESI purchases power and procures fossil fuels on behalf of the individual Operating Companies. Fossil fuel costs are borne directly by the Operating Company that contracts for and uses the fuel. Once resources are procured to meet forecasted demand, the system is operated during the current day using all of the resources available to the system to meet the total system demand. Throughout the course of the day, system operators may modify planned operations to maintain reliability, take advantage of less-expensive resources in the hourly wholesale power markets, or make off-system sales. For example, when spot market power purchases are available at a cost lower than the cost of energy that can be generated by units owned by the Operating Companies, that energy is purchased to displace owned generation, subject to operating constraints.[1035]

[1034] *Application of Gulf States Utilities Company to Reconcile its Fuel Costs*, Docket No. 15102, Order on Rehearing at 2 (Jun. 24, 1997).

[1035] ETI Ex. 40 (Thiry Direct) at 18-21.

Expenses for coal, gas, power purchases, and fuel oil are incurred directly by the respective Operating Company. For example, if coal is purchased for ETI's share of Nelson Station, Unit 6, then ETI is responsible for the invoiced cost and makes payment directly to the supplier. Wholesale power, purchased and sold for the system, however, is accounted for per the terms of the System Agreement. After dispatch, or after-the-fact, the System Agreement prescribes an accounting protocol to bill the costs of operating the system to the individual Operating Companies.[1036]

The following Fuel Reconciliation-related issues were uncontested:

➢ ***Natural Gas Purchases***

ETI witness Karen McIlvoy presented direct testimony describing ETI's natural gas procurement policies and strategies. She explained that the Company buys gas through a long-term contract with Enbridge, through participation in the monthly and daily markets depending on fuel needs, and on a delivered-to-plant basis or arrange for transportation to the plant. Ms. McIlvoy described how the gas buyers for ETI survey the markets and solicit offers for gas supplies. Ms. McIlvoy also provided a comparison of the Company's gas costs to the *Inside FERC* and *Gas Daily* published indices for the Houston Ship Channel.[1037] No party challenged the Company's natural gas purchases.

➢ ***Fuel Oil***

Ms. McIlvoy testified that the Company purchased fuel oil for start-up and flame stabilization at certain units. Fuel oil can also be used for emergency back-up fuel or as an economic alternative to natural gas at certain units. During the Reconciliation Period, the Company purchased all fuel oil on a short-term basis from spot market sources after solicitation of bids from multiple potential suppliers.[1038] No party contested ETI's fuel oil costs.

[1036] ETI Ex. 39 (Cicio Direct) at 31-37.

[1037] ETI Ex. 28 (McIlvoy Direct) at 23, Ex. KDM-3.

[1038] ETI Ex. 28 (McIlvoy Direct) at 5-6.

➢ *Longer-Term Purchased Power*

ETI witness Robert R. Cooper addressed the Entergy system's long-term planning process and described the Strategic Resource Plan process. He explained how the system determined its capabilities and needs for additional resources to reliably serve system load requirements. Mr. Cooper described the process by which the system developed requests for proposals and analyzed a combination of capacity and firm energy contracts to satisfy the system's identified resource needs.[1039] A portion of these system purchases was allocated to ETI. No party proposed a disallowance of these purchases on the basis of prudence.

➢ *Short-Term Purchased Power*

Ms. Thiry described the Power Marketing Team's procurement strategies, practices and procedures during the Reconciliation Period. Ms. Thiry testified that the Power Marketing Team fulfilled its objective of purchasing energy in the wholesale market when it was more economical than using the system's generation and in order to maintain system reliability. Ms. Thiry demonstrated that third-party purchases for the system compared favorably to market price indices and to proxy costs of avoided generation.[1040] The Power Marketing Team maintained effective cost controls and procured a diverse portfolio of product to provide electricity for customers at a reasonable cost.[1041] No party contested the prudence of ETI's short-term power purchases.

➢ *Coal Commodity and Transportation*

ETI has ownership interest and/or obtains power through Schedule MSS-4 of the Entergy System Agreement, in two coal-burning generating units – Nelson and BCII/U3. ETI owns a 29.75 percent interest in Nelson 6 and operates the unit. ETI owns a 17.85 percent interest in BCII/U3, but the unit is operated by a third party. ETI witness Ryan Trushenski, the Manager of

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[1039] ETI Ex. 34 (Cooper Direct) at 6-10.

[1040] ETI Ex. 40 (Thiry Direct) at 24.

[1041] *Id.*

Coal Supply for ESI, testified that ETI prudently managed its coal supply and transportation expenses during the Reconciliation Period.[1042]

With respect to coal and transportation expenses at Nelson 6, ETI obtained coal during the Reconciliation Period under a supply contract previously reviewed by the Commission, and entered into a new coal supply contract after a competitive bid process. ETI chose the supplier with the lowest priced coal that met the specifications necessary for use at Nelson 6. Similarly, ETI arranged for transportation of coal according to transportation contracts previously reviewed in prior fuel reconciliations. When those contracts expired, ETI initiated a competitive bid process and chose the lowest cost option available that met its requirements. With respect to BCII/U3, ETI incurred costs to run the unit and took reasonable steps to ensure that the third party operator properly charged for coal and transportation expenses under an arrangement previously reviewed and approved in prior fuel reconciliations.[1043] No party challenged the reasonableness and necessity of ETI's coal or transportation expense during the Reconciliation Period

The three contested issues are discussed below.

A. Spindletop Gas Storage Facility

During the Reconciliation Period, ETI incurred $10,261,663 of non-fuel expense associated with operating the Spindletop Facility. Cities challenged ETI's use of the Spindletop Facility, arguing that the costs of operating it outweigh the benefits gained from it. For the same reason he challenged the Spindletop Facility costs associated with rate base, Cities witness Nalepa also challenges ETI's non-fuel expense associated with the facility. Specifically, Mr. Nalepa recommends that ETI's total fuel reconciliation balance be reduced by $6,595,290, which he calculates as the difference between the $10,261,633 non-fuel operational costs associated with the Spindletop Facility over the Reconciliation Period and the costs of alternative sources of providing a reliable and flexible gas supply over the same period.[1044] In Section V.H., above, the ALJs rejected

[1042] ETI Ex. 33 (Trushenski Direct) at 2.

[1043] *Id.* at 11-13.

[1044] Cities Ex. 6 (Nalepa Direct) at 42-43; Cities Initial Brief at 84.

Cities' contention that the Spindletop Facility is not used or useful. For the same reason they rejected Cities' Spindletop Facility arguments relevant to rate base, the ALJs also reject Cities' Spindletop Facility arguments relevant to Fuel Reconciliation.

B. Use of Current Line Losses for Fuel Cost Allocation

Cities propose that the allocation of fuel costs incurred over the Reconciliation Period reflect the current line loss study performed by ETI for this case and recommended for approval on a going forward basis. In the fuel reconciliation case, ETI proposes to allocate costs to customers using a line loss study performed in 1997, which Cities claim does not reflect the current cost of providing service to the current wholesale customers and to the various retail customers.[1045] According to Cities, updating ETI's allocation of fuel costs to reflect current line losses and the cost of providing service to customers results in a \$3,981,271 reduction to the Texas retail fuel expenses incurred over the Reconciliation Period.[1046]

ETI responds that the Cities' recommendation is unprecedented. It notes that the Commission's substantive rules *require* use of "a *commission-approved* adjustment to account for line losses corresponding to the voltage at which the electric service is provided."[1047] Moreover, ETI argues that retroactive use of new loss factors to calculate its fuel over/under-recovery balance would result in a mismatch between the revenues recovered under the fuel factor and the costs billed and allocated to the various customer classes.[1048]

Fuel costs are collected through Commission-approved fixed fuel factors. One of the elements the fuel factor is required to take into account is line losses. P.U.C. SUBST. R. 25.237(c)(2)(B) states that the utility must prove that: "the proposed fuel factors utilize a *commission-approved* adjustment to account for line losses corresponding to the voltage at which the

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1045 Cities Ex. 6 (Napala Direct) at 44; *see also* Tr. at 1469-1470.

1046 Cities Ex. 6 (Napala Direct) at 47, Table 14.

1047 ETI Ex. 58 (McCloskey Rebuttal) at 2, *quoting* P.U.C. SUBST. R. 25.237(c)(2)(B) (emphasis added).

1048 Tr. at 1484.

electric service is provided."[1049] If the Commission were to adopt Cities' recommendation that the newly-developed line losses be used in the reconciliation of fuel costs, the allocation of those costs would not match the collections (determined through the use of historical line losses). This mismatch could result in some customers receiving more than they are entitled and others receiving less than they are entitled. The ALJs find that the Commission's rules require the use of Commission-approved line losses that were in effect at the time fuel costs were billed to customers in a fuel reconciliation. The ALJs, therefore, recommend that the Commission reject the Cities' proposed adjustment.

C. ETI's Special Circumstances Request

In the application, ETI seeks to include $99,715 in the Fuel Reconciliation to allow it to recover "the reversal of certain credits that were previously included in the Company's [Incremental Purchased Capacity Rider] Rider IPCR."[1050] ETI witness Zakrzewski explained that the FERC revised the amount of purchased capacity-related production costs allocable to ETI through the FERC-approved Rough Production Cost Equalization mechanism for allocating production costs among the Operating Companies. As Mr. Zakrzewski explained, the result of the decision was a recalculation of ETI's capacity costs recoverable through the Commission-approved Rider IPCR, which expired during the Reconciliation Period.[1051]

During the hearing, no party contested ETI's special circumstances request of $99,715 with regard to the IPCR-related adjustment. For the first time in its Initial Brief, however, Cities opposed the request, asserting that it conflicts with the settlement reached in Docket No. 37744.[1052] The ALJs are not swayed by Cities' argument. As pointed out by ETI,[1053] Cities provided no testimony or other evidence to support its position. Furthermore, Cities failed to explain how a settlement agreement reached in Docket No. 37744 could or should trump the FERC's jurisdiction to determine

[1049] P.U.C. SUBST. R. 25.237(c)(2)(B) (emphasis added).

[1050] ETI Ex. 23 (Zakrzewski Direct) at 13.

[1051] *Id.*

[1052] Cities Initial Brief at 86.

[1053] ETI Reply Brief at 93.

the amount of purchased capacity costs attributable to ETI. The only evidence in the record supports ETI's recovery of these costs. Accordingly, the ALJs recommend that these FERC-imposed costs should be found to be recoverable and Cities' request to deny their recovery should be rejected.

In summary, the ALJs conclude that, consistent with the requirements of P.U.C. SUBST. R. 25.236(d)(1), ETI met its burden to prove that: (1) its eligible fuel expenses during the Reconciliation Period were reasonable and necessary expenses incurred to provide reliable electric service to its retail customers; (2) the prices charges by its affiliates were reasonable and necessary and no higher than the prices charged by the supplying affiliates to other affiliates or to unaffiliated persons; and (3) ETI has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the Reconciliation Period.

XII. OTHER ISSUES

A. MISO Transition Expenses [Germane to Preliminary Order Issue Nos. 6-8 and Docket No. 39741 Preliminary Order Issue Nos. 1-9]

Entergy is seeking to transfer operational control of the Entergy Operating Companies' transmission assets to the MISO Regional Transmission Organization (RTO). ETI expects its share of the costs for this transfer will include approximately $17 million of expense.[1054] ETI has made two alternate proposals to recover these expenses. ETI's first proposal requests the Commission to approve a deferred accounting of its transition expense incurred on or after January 1, 2011, and to approve accrual of interest on the deferred amount at ETI's overall rate of return. Under this proposal, ETI would present the resulting regulatory asset for review in a future proceeding. ETI originally requested this deferred accounting in Docket No. 39741, which was later consolidated into this case for all purposes. In its Preliminary Order in Docket 39741, the Commission stated that it had authority to allow such a deferral of costs "when it is necessary to carry out a provision of PURA." It also stated that whether ETI's request met this requirement "hinges on the factual issue of necessity . . . ."

[1054] ETI Ex. 42 (Lewis Supplemental Direct) at 5.

As an alternative proposal, ETI requested the Commission to include $4 million of transition expense in base rates set in the present case, based on a three-year amortization of a total of $12 million in MISO transition expenses. ETI's Test Year MISO transition expenses totaled only $916,535, but ETI's request for deferred accounting addressed expenses incurred on or after January 1, 2011, which is after the Test Year concluded. ETI argues that its request is a conservative known and measureable change because the post-Test-Year expenses will be significantly more than $4 million per year. Further, these costs would be removed from ETI's cost of service if its deferred accounting proposal is approved.

As noted, ETI's proposals concern MISO transition expenses incurred on or after January 1, 2011. However, ETI also incurred $263,908 in these expenses during the 2010 portion of the Test Year. ETI has proposed a five-year amortization of this amount ($52,800 per year), assuming either its primary proposal or its alternative proposal is adopted. However, if ETI's primary and alternative proposals are both rejected, ETI requested that no reduction be made to its total Test Year amount of $916,535.[1055]

Cities, TIEC, State Agencies, and Staff opposed ETI's requests. They argue that ETI failed to establish that the proposed deferred accounting is necessary to carry out a provision of PURA, as required by the Commission's Preliminary Order. They also contended that ETI's alternate request to include $4 million in base rates is not a known and measureable change and should be disallowed.

The ALJs recommend that the Commission deny ETI's request for deferred accounting of its MISO transition expenses to be incurred on or after January 1, 2011. However, the ALJs do recommend that the Commission authorize ETI to include $2.4 million of MISO transition expense in base rates set in the present case, based on a five-year amortization of $12 million in total projected expenses.

[1055] ETI Ex. 42 (Lewis Supplemental Direct) at 4 and Adjustment No. 16.L.

1. Deferred Accounting

In support of its deferred accounting request, ETI cited *State v. Public Utility Comm'n of Texas*.[1056] In that case, the Texas Supreme Court stated that a deferred accounting is "necessary" when it will "ensure that the requirements of [PURA] are met."[1057] In ETI's opinion, deferred accounting is necessary in the present case to ensure that PURA §§ 36.051 and 36.003(a) are met (*i.e.*, that utilities have a reasonable opportunity to recover their expenses and receive reasonable rates). ETI also relied on *Hammack v. Public Utility Commission of Texas*, which stated that "a need . . . is a relative requirement, ranging from an imperative need to one that is minimal . . . ."[1058]

ETI-witness Brett Perlman testified that deferred accounting is also necessary to ensure the requirements of PURA § 31.001(c) are carried out.[1059] That section encourages development of a competitive wholesale electric market. ETI noted that the *Hammack* opinion stated that Section 31.001(c) amounts to a "legislative directive that the Commission formulate policies responsive to the needs of the emerging competitive wholesale market."[1060] Therefore, ETI asserted that RTO membership and deferred accounting are necessary because they will ensure that the Commission meets its obligation under Section 31.001(c). More specifically, ETI stated, both RTO membership and deferred accounting itself constitute examples of policies required by section 31.001(c) to support wholesale competition. Therefore, ETI argues that its request for deferred accounting should be approved because it is necessary to carry out PURA §§ 36.051, 36.003, and 31.001(c).[1061]

Cities argue that ETI's request for deferred accounting of MISO transition expenses should be denied because deferred accounting is not necessary to carry out any requirement of PURA.

1056 883 S.W.2d 190 (Tex. 1994).

1057 883 S.W.2d at 194.

1058 *Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 723-24 (Tex. App.—Austin 2004, pet. denied).

1059 ETI Ex. 43 (Perlman Supplemental Direct) at 7.

1060 131 S.W.3d at 723.

1061 ETI's Initial Brief at 231-234; ETI Ex. 42 (Lewis Supplemental Direct) at 2-4; ETI Ex. 43 (Perlman Supplemental Direct) at 5-7.

Cities witness James Brazell stated that ETI's proposed transition to MISO is not mandatory, and the anticipated expenses are not extraordinary. He added that ETI has been exploring membership in an RTO for over ten years and those costs have historically been included in ETI's base rates; therefore, he concluded that deferred accounting was not necessary in the past and is not necessary now. Cities stressed that ETI conceded that deferred accounting of these expenses is not necessary to maintain its financial integrity, and in Cities' opinion, both *State v. Public Utility Comm'n of Texas*,[1062] and the Commission's Preliminary Order require a showing of impairment of financial integrity to conclude that deferred accounting is necessary to comply with PURA § 36.051. Cities also stated that ETI failed to show that deferred accounting is necessary to comply with PURA §§ 36.003 and 31.001(c); therefore, Cities argues that ETI's request for deferred accounting should be denied.

TIEC also opposed ETI's request for deferred accounting, arguing that ETI failed to demonstrate that it is necessary to carry out PURA §§ 36.051, 36.003, or 31.001(c). TIEC witness Jeffry Pollock stated there is no indication that deferred accounting treatment is necessary for ETI to earn a reasonable return on its invested capital or that denying the deferred accounting would prevent ETI from having just and reasonable rates. Further, Mr. Pollock asserted there is no evidence that a lack of deferred accounting treatment for ETI would prevent Entergy from pursuing its MISO proposal.[1063] Mr. Pollock added that ETI has incurred other similar costs to carry out various purposes of PURA without deferred accounting. For example, since 2005, ETI has spent nearly $20 million pursuing various similar activities, including transitioning to competition, investigating RTO options, examining changes to the Entergy System Agreement, and supporting the Entergy OATT. Yet, ETI did not seek deferred accounting for any of those costs. Finally, Mr. Pollock testified that the projected transition costs are not material. He noted that ETI expects to incur $17 million of transition costs.[1064] This equates to $5.8 million per year, which is only 1 percent of ETI's Test Year operating revenues, according to Mr. Pollock. In his opinion, this level of MISO transition costs is easily subsumed in the normal variation in ETI's year-to-year expenses.[1065]

[1062] 883 S.W.2d 190 (Tex. 1994).

[1063] TIEC Ex. 1 (Pollock Direct) at 46-47.

[1064] ETI Ex. 42 (Lewis Supplemental Direct) at 5.

[1065] ETI Ex. 1 (Pollock Direct) at 48-49 and Ex. JP-8.

TIEC also disagreed with ETI's interpretation of *State v. Public Utility Comm'n of Texas*.[1066] In TIEC's view, that case held that deferred accounting is necessary only when needed to protect the financial integrity of the utility. Likewise, TIEC disagreed with ETI's argument that *Hammack*[1067] held that "need" is a relative requirement that must be viewed in light of legislative policy directives.[1068] TIEC noted that *Hammack* had nothing to do with deferred accounting. Instead, it was limited to the issue of whether, in granting a certificate of convenience and necessity for a transmission line under PURA §37.056, the Commission should include evidence that considered customers and market participants throughout the state.[1069] In TIEC's view, the *Hammack* case is irrelevant in determining whether deferred accounting is necessary to carry out the provisions of PURA §§ 36.003, 36.051, and 31.003(c). State Agencies made similar arguments.

Commission Staff also argues that ETI did not establish why deferred accounting is necessary to carry out a provision of PURA. In Staff's view, the applicable court cases and other precedent required ETI to show that deferred accounting is necessary to maintain its financial integrity, in order to carry out the provisions of PURA § 36.051. Staff argues that the Commission's Preliminary Order did not reject the financial integrity standard when it stated: "[t]his standard is not appropriate, however, for all circumstances and the Commission has applied different standards in various circumstances."[1070] Rather, Staff stated, the Commission merely declined to designate a specific standard.

Staff also rejected ETI's argument that deferred accounting will "ensure that the Commission meets its obligation under Section 31.001(c) to support the achievement of a competitive wholesale market."[1071] First, Staff noted, the Commission stated in the Preliminary Order that merely showing

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1066 883 S.W.2d 190 (Tex. 1994).

1067 *Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 723-24 (Tex. App.—Austin 2004, pet. denied).

1068 ETI Initial Brief at 232-233.

1069 *Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 724 (Tex .App.−Austin 2004, pet. denied).

1070 *Application of Entergy Texas, Inc. for Authority to Defer Expenses Related to its Proposed Transition to Membership in The Midwest Independent Transmission System Operator*, Docket No. 39741 Preliminary Order at 9 (Sep. 2, 2011).

1071 ETI Initial Brief at 234.

movement towards a policy goal is not a sufficient standard upon which to approve deferral.[1072] Thus, ETI's statement that deferred accounting will "support" wholesale competition addresses a standard that the Commission already rejected. Second, Staff argues that ETI failed establish that deferred accounting is "necessary" to support a competitive wholesale market or that failure to allow deferred accounting would prevent that goal. In other words, ETI did not show that, absent deferral, it would not join MISO; thus, ETI did not show how deferral would "ensure" that it joins an RTO. Therefore, Staff concluded, because ETI failed to prove that deferred accounting is necessary to carry out any provision of PURA, ETI's request should be denied.

In response to these arguments, ETI noted that no party disputed that the Commission may grant deferred accounting "when it is necessary to carry out a provision of PURA." It also argues that Staff and intervenors misinterpreted *State v. Public Utility Comm'n of Texas*[1073] as holding that deferred accounting is necessary to carry out PURA § 36.051 only when a utility's financial integrity is at stake. Although lack of financial integrity is an indication that PURA § 36.051 has not been carried out, ETI noted that this section contains other express requirements that can be met through deferred accounting, such as ensuring utilities a reasonable opportunity to recover their costs. ETI also cited other Commission cases in which it authorized deferred accounting when financial integrity was not at stake, such as deferral of rate case expenses and merger costs for subsequent review and recovery.[1074] ETI added that deferred accounting would permit the Commission to review ETI's transition expenses in a subsequent proceeding, after determining whether ETI's transition to MISO is in the public interest. Thus, under ETI's proposal, there is no risk that ETI would recover such costs absent a finding that they are reasonable and necessary.

As for Staff and TIEC's argument that deferred accounting is not necessary to carry out PURA § 31.001(c), ETI argues that the "necessary" standard is not a "but for" test. In response to arguments that the proposed deferred accounting will merely further policy objectives of Section 31.001(c), which the Commission has deemed insufficient to meet the "necessary"

[1072] Docket No. 39741, Preliminary Order at 11.

[1073] 883 S.W.2d 190 (Tex. 1994).

[1074] ETI Reply Brief at 95-96.

standard,[1075] ETI reiterated that the *Hammack* opinion held that "the Commission's interpretation of need must be viewed in light of the legislative directive that the Commission formulate policies responsive to the needs of the emerging competitive wholesale market," as well as "overall policy objectives."[1076] Thus, ETI argues, that it has demonstrated that deferred accounting is necessary to carry out Section 31.001(c) – *i.e.*, it will "ensure" that the requirements of that provision are carried out, and in particular ensure that the Legislature's specific instruction to develop the wholesale market is carried out.[1077]

Although ETI's proposal for deferred accounting has some practical appeal, the ALJs conclude that ETI has not shown that it is necessary to carry out a provision of PURA. The ALJs find that ETI was not required to show that a deferred accounting is necessary to maintain its financial integrity, as argued by intervenors. In *State v. Public Utility Comm'n of Texas,*[1078] the Texas Supreme Court held that preserving the financial integrity of a utility was necessary to carry out a provision of PURA, and thus justified deferred accounting for certain expenses in that case, but the court did not hold that preserving financial integrity was the sole basis upon which a deferred accounting could be approved. Likewise, in its Preliminary Order for the present case, the Commission stated: "This standard [financial integrity] is not appropriate, however, for all circumstances and the Commission has applied different standards in various circumstances, although none of these standards or circumstances has been reviewed by any court."[1079] On the other hand, the ALJs also find that ETI's contention that deferred accounting of the MISO transition expenses will help the development of a competitive wholesale electric market, as described in PURA § 31.001(c), is not sufficient to authorize deferred accounting. Again, the Commission stated

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[1075] Docket No. 39741, Preliminary Order at 7.

[1076] *Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 723-24 (Tex. App.—Austin 2004, pet. denied).

[1077] ETI Reply Brief at 97-99.

[1078] 883 S.W.2d 190 (Tex. 1994).

[1079] Docket No. 39741, Preliminary Order at 9 (Nov. 22, 2011).

in the Preliminary Order that "to carry out a provision of PURA" means more than undefined progress or movement towards a statutory objective.[1080]

The Commission made clear that ETI's burden was not only to show that a provision of PURA would be carried out by an accounting deferral of the MISO transition expenses, but that the deferral is *necessary* to carry out that provision. The Commission added that necessity was a question of fact that "can only be determined after development of an adequate factual record that demonstrates the necessity, of whatever degree."[1081] Intervenors argue that Entergy's efforts to transfer operational control of the Entergy Operating Companies' transmission assets to MISO will proceed with or without the deferred accounting requested by ETI; thus, deferred accounting is not necessary. Likewise, intervenors argue that ETI's alternate proposal to recover the transition costs through base rates shows that deferred accounting is not necessary. ETI, however, asserted that necessity should not be considered a "but for" requirement. It noted that no provision of PURA would be impossible to carry out absent a deferral of rate case expenses or merger expenses, yet the Commission has allowed deferred accounting of such expenses in other cases. ETI also cited the statement in *Hammack v. Public Utility Commission of Texas* that "a need . . . is a relative requirement, ranging from an imperative need to one that is minimal . . . ."[1082] Intervenors criticized ETI's reliance on the *Hammack* case because it concerned a transmission line. While that is correct, the case does make the general point that the question of need is not an absolute "but for" test. This is also consistent with the Commission's statement in the Preliminary Order that ETI's burden was to demonstrate necessity, "of whatever degree."

ETI's complaint is that its MISO transition expenses will soon increase above the Test Year amount, from $916,535 for the Test Year to over $5 million per year, but it will not be able to recover the increased costs through normal Test Year cost-of-service ratemaking principles. Thus, although ETI's financial integrity may not be jeopardized, ETI argues that it nevertheless will not be able to have a reasonable opportunity to recover its expenses and receive reasonable rates as required

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[1080] *Id.* at 11.

[1081] *Id.* at 8.

[1082] *Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 723-24 (Tex. App.—Austin 2004, pet. denied).

by PURA §§ 36.051 and 36.003(a). Therefore, ETI believes the proposed deferred accounting is necessary to carry out those provisions of PURA.

The ALJs find that the essence of ETI's complaint is that regulatory lag works against it in this particular situation. But as noted by the court in *State v. Public Utility Comm'n of Texas*, regulatory lag is an ordinary element of risk for utilities.[1083] One of the characteristics of Test Year cost-of-service ratemaking is that some expenses upon which rates are based may go up and others may go down during the time the rates are in effect. Such changes can be corrected in future ratemaking proceedings, but in this case ETI desires to ensure that it will recover all of its MISO transition costs. But *State v. Public Utility Comm'n of Texas* and the Commission's Preliminary Order in this case make clear that eliminating the normal effects of regulatory lag by allowing a deferred accounting should not be undertaken lightly. If ETI's arguments were taken to their extreme, a utility could obtain deferred accounting any time it anticipated a post Test Year increase in a particular expense, under the argument that it must be allowed to recover all of its expenses to carry out the requirements of PURA §§ 36.051 and 36.003(a). In this case, ETI's estimated MISO transition costs will equal about $5.8 million per year. As Mr. Pollock noted, this is only one percent of ETI's Test Year operating revenues, which may easily be subsumed in the normal variation in ETI's year-to-year expenses. Under these circumstances, ETI has not shown that granting its requested deferred accounting is necessary to carry out the requirements of PURA §§ 36.051 and 36.003(a) that it receive just and reasonable rates. Therefore, the ALJs recommend that the Commission deny ETI's request for deferred accounting treatment of its MISO transition expenses to be incurred on or after January 1, 2011.

2. Base Rate Recovery

As mentioned above, if the Commission denies ETI's request for deferred accounting, ETI requested the Commission to include $4 million of MISO transition expense in base rates set in the present case, based on a three-year amortization of $12 million in total projected expenses.

[1083] 883 S.W.2d 190, 196 (Tex. 1994).

Cities disputed the amount of MISO expenses ETI requested in this proposal. Cities witness Mark Garrett testified that a $4 million annual expense is inconsistent with ETI's own projected costs. The Test Year expenses were $916,535, and the actual expenses incurred during January through November 2011 were only $2.513 million, which annualized would be $2.742 million.. For 2013, ETI projected MISO transition expenses of only $2.587 million, although ETI's projected 2012 level of $8.9 million. However, Mr. Garrett added that 2012 is an estimated level and is not consistent with actual 2011 results. In his opinion, the actual 2011 level of about $2.7 million or the expected 2013 level of about $2.6 million should be the outside range of what the Commission should use for setting prospective rates. In any event, however, Cities argue that these projected levels are not sufficiently known and measurable to include for ratemaking purposes. Cities pointed out that it is unknown whether ETI's proposed move to MISO will even be approved, or whether the ETI will even continue to incur costs toward a MISO transition. Therefore, Cities argues that only the Test Year level of $916,535 should be included in rates, which would result in a downward adjustment of $3,083,462 to ETI's request.[1084]

TIEC also argues that ETI's alternative proposal should be rejected. Mr. Pollock complained that this proposal would allow ETI to recover post Test Year expenses that are not known and measureable. Mr. Pollock noted that ETI's own estimate of its share of transition costs has changed. When ETI filed its request for deferred accounting in Docket No. 39741, it estimated transition costs of $12 million. Now it estimates costs of $17 million, an increase of over 40 percent. Further, Mr. Pollock stated, ETI based its share of the estimated transition costs by assuming a 17 percent responsibility ratio, but ETI's future responsibility ratios are not known because they are based on projected growth rates of ETI relative other Entergy Operating Companies. Thus, Mr. Pollock concluded that ETI's share of future MISO transition costs cannot be appropriately measured.[1085] In summary, TIEC argues that the Commission should deny ETI's request for deferred accounting and

[1084] Cities Ex. 2 (Garrett Direct) at 61-63 and Ex. MG2.14; Cities Initial Brief at 89-91; Cities Reply Brief at 112-113.

[1085] TIEC Ex. 1 (Pollock Direct) at 49-50.

should allow ETI to recover only Test Year MISO transition expenses.[1086] Commission Staff made arguments similar to Cities and TIEC.[1087]

In response, ETI argues that the $4 million annual expense requested is known and measurable. ETI noted that it already incurred over $3.6 million in transition expense in the nine months since the end of the Test Year,[1088] which equates to $4.8 million on an annual basis. Furthermore, ETI's expects $17 million in transition expenses to be incurred over three years, which equates to $5.8 million annually.[1089] In ETI's view, the issue is whether it is sufficiently known that ETI will incur at least $12 million in transition expense, not whether ETI can predict an exact level of future expense.[1090]

The ALJs recommend that the Commission authorize ETI to include $2.4 million in base rates set in the present case for MISO transition expense incurred on or after January 2, 2011, based on a five-year amortization of $12 million in total projected expenses. The primary argument of intervenors against the adjustment is that the total of $12 million is not a known and measurable change. However, the ALJs find that ETI's evidence established that such expenses will total *at least* $12 million. It is true that the Test Year expenses were less, but ETI filed its application to effectuate the transfer to MISO in 2012, so it is clear that those expenses will increase significantly to levels well above the Test Year amount. It is true that ETI has not established the precise total amount of MISO transition expenses it will incur, but the ALJs find that those expenses will likely exceed the $12 million included in ETI's request. ETI requested that the $12 million total be amortized over three years, which would produce a $4 million annual cost. However, ETI also requested to amortize over five years its $263,908 in MISO transition expenses that were incurred during the 2010 portion of the Test Year ($52,800 per year). If a five-year amortization is appropriate for those expenses, a five-year amortization would also be appropriate for the post Test Year MISO transition expenses. Therefore, the ALJs recommend that the Commission authorize

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1086 TIEC Initial Brief at 97-98; TIEC Reply Brief at 70-71.

1087 Staff Reply Brief at 65-66.

1088 ETI Ex. 46 (Considine Rebuttal), Ex. MPC-R-1.

1089 TIEC Ex. 1 (Pollock Direct) at 48:3-4.

1090 ETI Initial Brief at 236-239; ETI Reply Brief at 99-100.