PROJECT NO. 39246

RULEMAKING PROCEEDING	**§**	**PUBLIC UTILITY COMMISSION**
CONCERNING RECOVERY OF	**§**	
PURCHASED POWER CAPACITY	**§**	**OF TEXAS**
COSTS, INCLUDING AMENDMENT	**§**	
OF SUBST. R. 25.238	**§**	

ORDER ADOPTING REPEAL OF §25.238 AND NEW §25.238
AS APPROVED AT THE MAY 9, 2013 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts the repeal of §25.238, relating to Power Cost Recovery Factors (PCRF) with no changes, and new §25.238, relating to Purchased Power Capacity Cost Recovery Factor (PCRF) with changes to the proposed text as published in the November 30, 2012 issue of the *Texas Register* (37 TexReg 9421). The new rule provides a mechanism, outside of a base-rate proceeding, by which an electric utility may seek to timely recover certain reasonable and necessary purchased power capacity costs incurred in the course of providing reliable electric service to ratepayers. The rule enables a utility to apply to establish a PCRF rider with the requirement that it be adjusted once a year to reflect appropriate costs, changes in demand, over- and under-recoveries, and changes in revenues resulting from load growth. The rule provides for the reconciliation of costs recovered through a PCRF at least once every three years, in conjunction with a fuel reconciliation proceeding. The rule also provides a process wherein a utility may seek commission review of an arrangement for the purchase of power capacity, including purchases from affiliates of the utility, prior to the utility seeking recovery of the associated capacity expenses in a PCRF proceeding. The new rule increases regulatory certainty, reduces regulatory lag, and balances the occasionally disparate interests of the affected parties.

The commission received initial comments on the proposed rule from cities in Entergy Texas Inc.'s service area: Anahuac, Bridge City, Conroe, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Silsbee, Sour Lake, Vidor, and West Orange (collectively Cities); El Paso Electric Company (EPE); Entergy Texas, Inc. (ETI); Office of Public Utility Council (OPUC); Sharyland Utilities, L.P. (Sharyland); Southwestern Electric Power Company (SWEPCO); Southwestern Public Service Company (SPS); the State of Texas's agencies and institutions of higher learning (State Agencies); and Texas Industrial Electric Consumers (TIEC).

In addition to comments on the proposed rule, the commission received comments in response to the following preamble questions:

1. Should the proposed rule allow for the inclusion of the cost of firm energy purchases from unaffiliated entities along with the cost of purchased power capacity for recovery via the PCRF? If so, should subsection (i) of the proposed rule be amended to require crediting of off-system firm energy sales?
2. Should the proposed rule address purchases from a qualifying facility under the Public Utility Regulatory Policies Act? If so, how?
3. Should a process be established wherein a utility may seek commission review of a utility's purchase of power capacity or firm energy from an affiliate so that the utility may thereafter seek to include the costs of such a commission-approved purchase in its purchased power capacity cost recovery rider?

4. If the commission establishes the review process described in question 3, should such a process be available for both bilateral, wholesale market purchases as well as purchases made pursuant to a tariff of a Regional Transmission Organization and/or Independent System Operator (RTO/ISO)?

5. If the commission establishes the review process described in question 3, should it limit the frequency of such reviews in order to limit the intervenor and commission resources devoted to such reviews?

Preamble question one:

A majority of the parties, including Cities, EPE, ETI, OPUC, SWEPCO, and TIEC, stated they do not believe it is necessary to include the cost of firm energy purchases in the proposed rule, as firm energy costs are recoverable through a utility's fuel rider. EPE stated that firm energy purchases are energy and not capacity purchases, and therefore should be recovered as energy costs and not capacity costs. OPUC noted that energy purchases are already eligible for recovery through the fuel factor, which is adjusted regularly. TIEC stated that the commission should avoid creating another avenue for recovery of the same costs, which could further complicate the regulatory framework and lead to unintended consequences. However, SPS commented that the cost of firm energy purchases from unaffiliated entities along with the cost of purchased power capacity should be included for recovery via the PCRF.

SWEPCO stated that firm and non-firm energy purchases scheduled to meet hourly energy requirements of the utility are distinct and separate from the contracted capacity purchases made to meet a utility's annual planning reserve requirements. SWEPCO stated that energy purchases are comparable to the output of the utility's electric generating plants, because fuel costs used to generate energy from the utility's plants are reviewed through the fuel reconciliation process, making it logical to address the firm and non-firm energy purchases through the same process. SWEPCO stated that what primarily differentiates a firm versus non-firm purchase is the seller's obligation to deliver energy, the seller's flexibility to curtail transactions due to changes in the market prices or generation resource availability, and the buyer's obligation to carry operating reserves to back up non-firm purchases in the event the transaction is curtailed by the seller. SWEPCO stated that, once scheduled, energy from both firm and non-firm purchases have a similar impact on how the utility's own resources are dispatched. SWEPCO stated that, from a cost recovery standpoint, capacity costs are allocated to the customer classes on a demand ratio basis whereas both firm and non-firm energy purchases are allocated based on energy consumption, and it would therefore not make sense to combine the cost of firm energy purchases with capacity purchases.

EPE and ETI stated that if the commission determines that a portion of the cost of a firm energy purchase is capacity and imputes a capacity component to the purchase, the utility should be allowed to include that portion in the PCRF; otherwise, the imputed capacity associated with the firm energy purchase would be caught between requirements for eligible fuel costs, which exclude capacity costs per P.U.C. SUBST. R. §25.236(a)(4), and the PCRF, which is for capacity costs only. In reply comments, OPUC stated that it agreed with this proposal should the commission determine that a particular firm energy purchase includes a capacity component.

TIEC stated in reply comments that, although block purchases of power are often priced on a per-kilowatt-hour (kWh) charge, they are in fact capacity purchases with an implicit demand charge, or margin, included in the energy price, and that the commission has previously determined that such imputed capacity is not recoverable as eligible fuel expense absent a special circumstance exception. TIEC agreed that these imputed capacity costs should not be eligible for recovery through the fuel factor, and the commission should avoid creating any such implication in this rulemaking. TIEC stated that, if imputed capacity costs are included in the proposed PCRF rule, it is critical that the PCRF also credit any of the utility's similar block power sales against the recoverable capacity costs to ensure that the resulting rates are balanced and do not result in over-recovery.

Parties including EPE, ETI, and SPS discussed the treatment of revenues from firm energy sales should the commission impute a capacity component. EPE stated that whether or not revenues from firm energy sales are considered the sale of capacity, the revenues will be fully accounted for in a fuel reconciliation proceeding because they will be used to offset fuel costs or determine the appropriate margin to credit. EPE noted that if firm energy sales included in the PCRF are a credit against capacity costs, there would first have to be a determination of the capacity component of each such firm energy sale so that the revenue could be divided between a credit against the capacity costs in the PCRF process and a credit in the fuel reconciliation. EPE opined that this seems to be an unnecessary burden when the revenue would be treated the same whether used to offset capacity or fuel or used to determine capacity sale margin or energy sale margin. ETI responded that it would not be necessary to include firm energy sales by a utility as a credit as they are already accounted for in the fuel reconciliation. SPS recommended crediting off-system firm energy sales in the PCRF reconciliation proceeding to better account for the overall recoveries and costs.

Commission response

The commission appreciates the comments of the parties. The commission agrees with the comments of Cities, EPE, ETI, OPUC, SWEPCO, and TIEC that it is not appropriate to provide for the recovery of firm energy purchases in this rule. Firm energy costs are already eligible for recovery through an electric utility's fuel rider, and the commission declines to create another avenue for recovery of the same costs. The commission further declines to address in this rule the imputation of a capacity component to firm energy purchases. Addressing imputed capacity purchases in this rule would introduce an unnecessary level of complexity and could lead to unintended consequences. The commission also agrees that costs recoverable under the fuel rules should not be included in the PCRF, and has added subsection (c)(3)(C) accordingly.

Preamble question two:

Cities, EPE, ETI, SWEPCO, and TIEC stated they did not believe a special provision was needed to address purchases from a qualifying facility (QF) if the proposed rule is adopted.

EPE and ETI asserted that under the language of the proposed rule, the cost of capacity purchases from QFs could be included in the same manner as any other non-affiliate capacity purchases, and that P.U.C. SUBST. R. §25.242 already addresses purchases from QFs under the Public Utility Regulatory Policies Act of 1978.

SWEPCO stated that the purchase of capacity from QFs does not seem to merit treatment any different from other purchases of capacity. SWEPCO noted that a 2008 Federal Energy Regulatory Commission (FERC) Order terminated the requirement that SWEPCO enter into a new purchase obligation or contract with qualifying facilities that have net capacity in excess of 20 megawatts (MW). SWEPCO stated that, accordingly, it amended its QF tariff schedule in Docket No. 35656 to close it to new purchases or contracts with QFs with net capacity in excess of 20 MW. SWEPCO stated that, for customers with net capacity of 20 MW and less, the applicable QF tariff defines the process for a monthly reconciliation of any non-firm energy purchases from a QF customer. SWEPCO noted that those energy costs are then recovered as a component of the fuel reconciliation.

SPS commented that the proposed rule should treat the recovery of capacity costs related to QF purchases in a manner similar to the rule's treatment of capacity costs incurred from other non-affiliate power purchase agreements.

Commission response

The commission agrees with the comments of Cities, EPE, ETI, SWEPCO, and TIEC that no special provision in the rule addressing capacity purchases from QFs is necessary. Excepting any costs recovered under the fuel rules, a utility may seek to recover the reasonable and necessary expenses of purchases of capacity from qualifying facilities in the same manner as any other non-affiliate capacity purchase.

Preamble question three:

Cities, OPUC, State Agencies, and TIEC generally opposed inclusion of purchases of capacity from an affiliate in a PCRF.

State Agencies stated that the appropriate forum for reviewing affiliate purchased power and capacity contracts is in a rate case rather than a PCRF proceeding, when a complete picture of the costs and revenues can be fully reviewed through established discovery and hearing. State Agencies argued that a broader expansion of the PCRF in a manner that would trump the existing rate case process for considering capacity contracts would run counter to the Public Utility Regulatory Act (PURA). State Agencies also commented that adding yet another review process to supplement the existing rate case process consumes commission and intervenor resources and unnecessarily drives up rate case expenses.

OPUC commented that the cost of power capacity or firm energy purchases from affiliates should not be eligible for recovery through the PCRF because the heightened standard governing affiliate transactions does not lend itself to extraordinary forms of relief, especially when the express goal of the PCRF is expedited processing. OPUC asserted that the commission order in ETI's most recent base-rate case speaks to the affiliate relationship and heightened affiliate standard.

Cities and OPUC argued that including the utility's purchases from affiliates would necessitate more time than what is contemplated under the proposed rule for processing a PCRF application in what is intended to be a streamlined process. OPUC stated that review of such transactions is not well-suited to an abbreviated proceeding such as a PCRF application, particularly not a shortened 90-day schedule as proposed by SWEPCO in its comments. OPUC acknowledged that, while a process could be crafted for the review of affiliate contracts, the administrative burden imposed on the commission and other parties would be significant, particularly when the base-rate process already exists through which recovery of such costs can be accomplished. OPUC asserted that the proposed rule strikes a balance between stakeholders' interests, one key element of which is the type of costs allowed for recovery through a PCRF. OPUC stated that if utilities are to be given a rate mechanism that allows for expedited recovery of capacity costs, which many stakeholders oppose, the costs eligible for recovery should, at a minimum, be restricted to capacity purchased from an unaffiliated utility. OPUC stated that the PCRF is an exceptional form of relief and should therefore be narrowly tailored to accomplish its stated purpose.

ETI, SPS, and SWEPCO generally supported the establishment of such a process wherein a utility may seek commission review of a utility's purchase of capacity from an affiliate so that the utility may thereafter seek to include the costs of such a commission-approved purchase in a PCRF. ETI, SPS, and SWEPCO stated that the exclusion of purchases of capacity from an affiliate will incentivize the utility against making such purchases, even though they may be the most cost-effective option.

TIEC stated in reply comments that ETI and SWEPCO make the disingenuous argument that allowing only non-affiliate contracts to be included in the proposed PCRF rule will bias capacity purchasing decisions. TIEC commented that utilities have a duty to make the most cost-effective capacity decisions for their ratepayers under the requirement that investments be reasonable and prudent, and operating expenses be reasonable and necessary. TIEC stated that to the extent that utilities allow such a bias to occur as a result of disparate ratemaking treatment, this is a general problem with any rule that examines only a subset of costs and is an argument against piecemeal ratemaking in general. TIEC further commented that, unless the rule is expanded to examine all capacity-related costs simultaneously, including installed generation capacity costs, it should be limited to non-affiliate purchases.

Cities noted in its reply comments that, in the past, ETI has based its requests to implement a capacity rulemaking on the claim that purchased power capacity costs are volatile. Cities stated that ETI's witnesses conceded in Docket No. 39896 that the vast majority of ETI's purchased power capacity costs are paid to affiliates through the Entergy System Agreement (ESA). Cities asserted that ETI's purchases are not market-driven, but are cost-based and subject to the control of the Entergy System Operating Committee, in which ETI representatives participate and vote.

SPS stated that the determination of whether the capacity purchased from an affiliate is just and reasonable should be made on a case-by-case basis and in conformity with other applicable commission rules and regulations such as PURA §36.058. SPS and SWEPCO stated that, if the utility presents evidence that the heightened standard for affiliate transactions is met, such purchases should be treated no differently than other purchases of capacity. SWEPCO stated that, to the extent capacity is purchased from an affiliate under a FERC-approved agreement, the commission should find that the affiliate standard has been met and allow inclusion of such purchases in the PCRF rider. SWEPCO stated that if capacity from the affiliate is purchased through a competitive solicitation process in which third parties are also bidding, and an independent monitor reviews bid solicitation and selection process, and that purchase meets the affiliate standards, then the commission should allow for the inclusion of such purchases in the PCRF as well.

ETI stated that, for the PCRF to work effectively, the rule should allow some means by which a utility can include all purchased power costs, including those costs attributable to an affiliate. ETI also commented that an important element of this rule should be to establish a process by which a utility and a seller of power may at any time, and irrespective of whether the utility has a PCRF, obtain a contemporaneous commission review of a purchased power contract, regardless of whether or not the contracting parties are affiliates. ETI proposed a provision setting forth such a process. ETI's proposed provision further stated that if the commission issues an order approving a purchased power contract, in any subsequent reconciliation or rate proceeding, the terms, conditions, and price shall be considered reasonable and necessary and shall not be subject to further review. ETI stated that providing for an approval process at the time a contract is entered would minimize risk of recovery and foster competition in the wholesale market. ETI stated that because the commission will have to make a determination at some time regarding the reasonableness of a purchase power arrangement, allowing it to be contemporaneously reviewed does not place any additional burden on the commission. ETI commented that the scope of review would be the same because all of the information that should be used for evaluating the purchased power contract would be available at the time it is entered. ETI further noted that the existing §25.328, subject to repeal in this project, provides a process for approval by the commission of a purchased power contract between an investor-owned distribution utility and an unregulated seller of power. ETI stated this decades-old process should be carried forward, but no longer be limited to just distribution utilities. ETI provided language for a proposed new subsection (k) and stated the proposed new subsection is worded so as to avoid arguments that, by adopting this specific provision, the commission has restricted itself from entertaining requests for approval of contracts outside of the context of the PCRF rule.

EPE and SWEPCO provided reply comments that supported ETI's proposal to add a subsection to the proposed rule that would allow a utility to voluntarily submit any purchased power agreement for prudence review. EPE and SWEPCO each commented that ETI's proposal reduces the uncertainty or regulatory risk associated with prudence reviews of purchased power agreements in rate cases or fuel reconciliations that are conducted years after an agreement has been entered. SWEPCO stated that a review at the time an agreement is entered would avoid the temptation to evaluate it using hindsight. SWEPCO further commented that ETI's proposed provision could also provide a mechanism for including affiliate purchases in the PCRF.

Cities and TIEC replied in opposition to ETI's proposal to establish a new pre-approval process for any purchased power capacity contract. TIEC stated that the process in the existing PCRF rule is explicitly limited to "distribution utilities," a term that does not include bundled utilities. TIEC commented that for bundled utilities, the prudence and reasonableness of a purchased power agreement cannot be effectively reviewed in isolation. TIEC stated that this review should remain in base-rate proceedings where all the necessary information is readily available. TIEC also commented that the type of pre-approval process ETI proposes would further disperse utility rate review into numerous unnecessary and inefficient proceedings, making it more difficult for customer groups to effectively participate and increasing the administrative burden on the commission. TIEC further stated that because ETI's proposal for contract pre-approval was not a part of the rule, the proposal is outside the scope of this rulemaking and would likely require a new rule to be published with a new opportunity for comments.

Cities commented that ETI requests the commission to issue an advisory opinion on the reasonableness of a utility's capacity contracts and then preclude any further review of the utility's costs incurred under such a contract. Cities stated that precluding further review of the contracts could potentially permit a utility to maintain capacity costs that have become inefficient and non-cost effective. Cities asserted that ETI's proposed process is unnecessary and would only serve to increase the number and frequency of regulatory proceedings.

Commission response

The commission declines to adopt a blanket exclusion from PCRF recovery for capacity purchases from an affiliate because doing so would introduce a regulatory bias that may discourage the acquisition of the most cost-effective capacity purchases to the detriment of ratepayers.

The commission agrees with the comments that adoption of an ex-ante review process will reduce regulatory uncertainty and allow for more timely review of purchases of capacity. The commission also agrees with the comments of OPUC that such a pre-approval process is not well-suited as part of a routine PCRF application. Therefore, the commission modifies the rule to establish a process through which a utility may voluntarily seek

commission review of an arrangement for a utility's purchase of power capacity. In recognition of the heightened standards of review applicable to an electric utility's payments to an affiliate, for purchases of capacity from an affiliate, such commission review and pre-approval is required before the utility may seek to include in the utility's PCRF the capacity costs related to the purchase.

The commission does not adopt ETI's proposal that once a purchased power contract has been approved by the commission, the reasonableness and necessity of costs arising from the contract shall not be subject to further review in any subsequent reconciliation or rate proceeding. Such a provision would in essence absolve a utility from ever-after prudently managing the costs associated with an approved purchased power contract. Rather, the pre-approval process adopted by the commission is intended to provide a utility with an opportunity to seek commission review of an arrangement for the purchase of capacity within a period of time that is reasonably contemporaneous with the execution of the contract. If granted, commission approval of such an arrangement provides more regulatory certainty regarding the prudence of entering into such a contract, without constituting a blank check for any and all future costs related to the arrangement.

The commission declines to adopt the suggestion by SWEPCO that capacity purchases from affiliates should be deemed to have met the affiliate standard under PURA if such purchases were made pursuant to a FERC-approved tariff. Rather, a pre-approval process is expected to give the commission sufficient time and an evidentiary record upon which to make the statutorily required findings regarding an affiliate transaction, while still

enabling the utility to later recover its approved capacity expenses in the more streamlined PCRF mechanism.

Consistent with the above response, subsections (c)(3)(A), (d), and (h)(1) of the rule have been modified accordingly.

Preamble question four:

ETI, SPS, and SWEPCO generally supported such a process for bilateral, wholesale market purchases as well as purchases made pursuant to an RTO/ISO tariff. ETI and SWEPCO stated that there was no reason to exclude such potentially beneficial purchases. SWEPCO stated that, if a review process is established, the commission will have an opportunity to consider whether such a purchase is reasonable, regardless of the type of purchase. SWEPCO stated that the rule should be clear that the RTO charges to be included in the PCRF are only those charges attributable to the installed capacity like markets administered by the RTO. SWEPCO noted that the Southwest Power Pool (SPP) does not administer such capacity markets at this time, so it does not anticipate any SPP RTO related costs in the recovery requests through the PCRF. SWEPCO stated that the PCRF should not include recovery of charges attributable to day-ahead and real-time market functions, even if those charges may appear to be distributed on a MW basis, because such expenses are already and more properly included in the fuel clause. SPS stated it could support including these types of purchases to the extent such approvals from the commission do not conflict with FERC approved rates and cause cost trapping.

Cities, OPUC, and TIEC opposed the inclusion of affiliate purchases in a PCRF. Cities stated that Texas customers should not be required to guarantee the profits and costs of affiliates no matter what entity approves the contract or tariff. TIEC stated that it opposes this process in general, and does not believe that it should be made available for bilateral, wholesale market purchases or purchases made pursuant to an RTO/ISO tariff.

Commission response

The commission agrees with ETI, SPS, and SWEPCO that a broad exclusion of purchases made via an RTO or an ISO is without merit. The commission further agrees with SWEPCO that RTO/ISO purchases made in day-ahead or real-time markets are not properly considered capacity purchases, and therefore that such purchases should be explicitly precluded from recovery under the rule. For the reasons discussed previously, the commission declines to adopt the recommendation of Cities, OPUC, and TIEC that affiliate purchases should be excluded from the PCRF. The commission instead adopts the requirement for an ex-ante commission review and approval before inclusion of affiliate-related purchases in the PCRF is allowed, including for any affiliate purchases made under any FERC-approved or RTO/ISO tariffs. Subsection (c)(3)(D) has been added accordingly.

Preamble question five:

SWEPCO asserted that the frequency of reviews can be limited by allowing the utility to seek exemption from review in certain circumstances. SWEPCO stated that once the commission reviews a FERC-approved agreement, and allows the utility to include the costs in the PCRF, the review should not be necessary for any further purchases under the same agreement. Similarly, SPS stated that once a purchase is approved by the commission for PCRF recovery, no further reviews of that purchase should be necessary. SWEPCO stated that the utility should be exempt from further reviews when a utility's competitive bidding process is reviewed by the commission and affiliate purchases from the Request for Proposal (RFP) process is permitted under the PCRF and it follows a similar RFP process.

SPS stated that limiting reviews would be appropriate to conserve intervenor and commission resources. SPS suggested that, to the extent a utility enters into future affiliate capacity purchases through a procurement process that the commission has previously found reasonable, the commission could establish a streamlined process for future applications and approvals.

ETI responded that, whether in a PCRF reconciliation or a rate proceeding, the commission evaluates an affiliate purchased power arrangement at the time it is entered or later, the commission will nonetheless have to make a determination of reasonableness, and that allowing for a review does not place any additional burden on the commission.

State Agencies and TIEC asserted that resources are best preserved by continuing to review capacity purchases in a base-rate case. TIEC stated that if the commission considers creating a new process for reviewing purchased power contracts outside of a base-rate case, it would support a limit on the number of reviews a utility can seek without filing a full base-rate case to ensure that utilities' rates are still comprehensively examined and adjusted on a regular basis.

Commission response

The commission declines to adopt SWEPCO's and SPS's recommendation that exempts from review certain affiliate purchases, as doing so is inappropriate given the higher standard of review for recovery of affiliate transactions. The commission agrees with the comments of State Agencies and TIEC that limiting the number and frequency of pre-approval filings is warranted in order to conserve commission and intervenor resources. Accordingly, subsection (d)(5) of the rule is added to limit pre-approval requests to one request per year, with a maximum of three requests allowed between major base-rate proceedings for the utility.

General Comments on the Proposed Rule

Necessity of PCRF

OPUC, State Agencies, Cities, and TIEC asserted that a PCRF is an unnecessary, extraordinary form of relief and that the current system that allows a utility to recover capacity costs through base rates, a longstanding practice that naturally takes into account load growth and other offsetting costs, does not need to be changed. TIEC asserted that this process also ensures that overall rates are reasonable and that both utility and ratepayer interests are satisfied. State Agencies and Cities noted that most utilities in the state have been able to recover purchased capacity costs within base rates. State Agencies asserted that the utilities' claim that the PCRF will provide "timely recovery" of costs implicitly suggests that base-rate recovery and the current rule do not already provide timely recovery purchased capacity costs under appropriate circumstances. Cities asserted that regulatory lag does not hinder timely recovery of costs. Cities noted that utilities must plan capacity purchases well in advance, giving ample time to file a base-rate case if warranted. TIEC noted that base-rate recovery of purchased power capacity costs leaves the decision of when and how to seek cost recovery to the utilities, which are free to file a base-rate case when it is necessary.

Several parties expressed concern that removing the recovery of purchased power capacity costs from base rates into a rider would also remove a utility's economic incentive to prudently manage costs between base-rate cases. State Agencies argued that direct cost recovery may be most needed when there is a lack of prudent cost management. Cities argued that regulatory lag incentivizes utilities to reduce costs and operate efficiently; rates are fixed in a base-rate case, and the utility can reduce costs to earn a profit. Cities argued that the base-rate recovery mechanism is economic, just, and efficient in providing utilities an opportunity to recover just and reasonable purchased power capacity costs.

TIEC stated that examining a single component of a utility's cost of service in isolation greatly increases the likelihood that overall rates will not be just and reasonable as required by PURA §36.051, because piecemeal ratemaking provides utilities an opportunity to selectively capture cost increases for certain items, while ignoring other potentially offsetting decreases. TIEC stated that this complexity creates serious problems for effective oversight and administration. TIEC argued that appropriate safeguards would require examining the costs and revenues of installed generation capacity, changes in retail load, and wholesale sales, which would save little in terms of economy and likely increase the overall resources and time that commission staff and customers devote to utility rate requests. Cities noted that the base-rate recovery does not require constant oversight and continual regulation like a piecemeal recovery mechanism.

TIEC stated that, given that installed and purchased capacity are substitutable from a customer perspective, allowing rate increases for purchased power capacity without simultaneously examining changes to installed generation costs makes it nearly impossible for a PCRF to appropriately protect consumers. TIEC stated that, rather than addressing these issues, the utilities instead seek to diminish oversight and reduce customer protection in the proposed rule. TIEC asserted that, at the very least, the requirements in the proposed rule to consider base-rate-related load growth, to limit the PCRF to actual, historical test year costs, and to credit customers for 100% of the margins from off-system capacity sales, should be retained. TIEC also stated that it does not believe the PCRF process will save commission or intervenor resources.

The utilities supported a rider for recovery of purchased power capacity costs. ETI stated that it has not been able to recover its increasing purchased capacity costs through base rates, and therefore needs a workable PCRF. EPE, SPS, and SWEPCO stated that a PCRF that allows for timely recovery of purchased capacity costs can benefit utilities and customers by providing for a more administratively efficient means of cost recovery without the cost, time, and regulatory lag typically associated with a base-rate proceeding. SPS argued that the PCRF advances the principles of cost causation and inter-generational equity and ensures that customers never pay more than actual costs incurred for purchased capacity.

SPS stated that short term contracts less than a year can be an economically efficient means to balance interim needs or extreme peaks associated with serving customers, which can result in cost savings for customers, but do not generally offer symmetrical benefits to a utility. SPS argued that, unless the new rule is approved, utilities will not be provided a similar opportunity to timely recover capacity costs. SPS stated that timely recovery of purchased capacity costs may decrease financing costs, thereby reducing overall customer costs, improving the utility's financial health, and ensuring its ability to make ongoing investments to improve the service quality for its customers.

ETI, SPS, and SWEPCO asserted that purchased capacity costs are expenses, not investments, and that the utility earns no profit on them as they are passed through to ratepayers at cost, as is fuel. ETI and SPS stated that the utilities must bear the risk associated with purchased capacity costs, even as customers reap savings. ETI stated that it continues to earn unattractive returns due mostly to its inability to recover its capacity costs under purchased power contracts, and is harmed by expense, delay, and regulatory risk incident to recovering the costs.

In reply comments, TIEC noted that utilities do not earn a return on any expenses, and there is no reason that purchased power capacity cost recovery should be treated differently from the way in which expenses are typically recovered. TIEC argued that, while the utility's rate of return is calculated on investments, the rate is set to compensate the utility for regulatory lag associated with both capital investments and expenses, and the idea that utilities are not compensated for the regulatory lag associated with expenses is simply false.

Commission response

Because of the vertically integrated utilities' increasing reliance on purchased power capacity and the problems that can arise under the traditional base-rate model, the

commission concludes that adopting a rule providing for a purchased power capacity rider is reasonable. A well-tailored purchased power capacity rider ensures that utilities are able to timely recover purchased power capacity costs should they need access to new sources of capacity, and will also mitigate the possibility that the utilities will over-recover such costs or receive a windfall.

The commission agrees with the comments of TIEC regarding the need for the rule to properly account for load growth and 100% of the margins from off-system sales, and additionally concludes that historical cost recovery and the inclusion in the rule of a small degree of regulatory lag strikes a reasonable balance between encouraging the utilities to remain prudent and cost-conscious in their purchases of capacity, while still allowing for more timely cost recovery than they would otherwise be able to attain under the traditional base-rate case model. Additionally, in recognition of the difficulty of striking a reasonable balance between occasionally competing interests, the commission intends in two years to review the operation and parties' use of the rule to determine whether provisions of the rule should be reevaluated.

Concerns Regarding Significant Over-Recovery

TIEC argued that installed generation capacity costs must be concurrently reviewed with a PCRF, because purchased power capacity and installed generating capacity are substitutable. TIEC gave an example that, under the proposed rule, a utility could sell one of its generating plants, replace that installed capacity with purchased power, and then increase rates through the proposed PCRF to capture the entire purchased power cost increase without accounting for any profits or cost savings associated with the plant sale. TIEC argued that this type of meaningful review of installed generation outside of a base-rate proceeding would not only be extremely complicated and time-consuming, but is also prohibited by PURA §36.201 and §36.204, which do not permit rates to be adjusted for installed generating capacity outside of a base-rate case. TIEC stated that costs associated with purchased power capacity and installed capacity should therefore continue to be reviewed in a base-rate proceeding.

The utilities generally recommended rejection of TIEC's argument on the grounds it was unrealistic. SPS responded that TIEC's example ignores the oversight of the commission and FERC over such transactions. SPS and SWEPCO stated that PURA §14.001 and §14.101 and P.U.C. SUBST. R. §25.74 govern public utility transactions of more than $10 million involving a sale, transfer, or merger of assets, and a utility is not allowed to sell, acquire, or lease a plant as an operating unit or system in the state unless the utility reports the transaction to the commission at least one working day before the transaction closes. ETI and SWEPCO noted that there would be an abundance of regulatory scrutiny over such a sale, and the commission would determine the reasonableness of such a transaction in a transparent process and could at that time consider how it should be accounted for in rates. SPS stated that if the commission determines that the transaction is not in the public interest, then the commission is required to take the effect of the transaction into consideration when setting the utility's rates and to disallow the adverse effect of the transaction on rates. SPS argued that TIEC's example assumes such a transaction would create a windfall, contrary to the public interest, and the commission and FERC would nonetheless approve such a transaction. SWEPCO argued that a utility is more likely to continue to invest in generation, noting that it, EPE, and SPS have all recently invested in new generation facilities.

Commission response

With respect to TIEC's hypothetical example regarding the sale of a utility-owned generating plant and the subsequent replacement of that capacity with purchased power capacity, the commission agrees with the comments of the utilities that such a sale would be broadly reported and its attendant impacts on the purchased power capacity rider reviewed at such a time. With respect to TIEC's concern about the necessity of reviewing installed generation simultaneously with a purchased power capacity rider, the commission recognizes that the complexity of such a task would prevent the utilities and customers from capturing the benefits of a streamlined PCRF process. Further, the inclusion in the rule of offsetting load growth revenues associated with installed capacity is intended to eliminate any over-recovery under the hypothetical situation described by TIEC. The commission also notes that the PCRF under the rule permits a utility to apply to establish a PCRF only if no more than two years have passed since the final order in a base-rate case, and that the PCRF will only recover purchased power capacity costs that are incurred in excess of costs recovered in base rates. The commission believes these safeguards for the PCRF should ensure that the utilities do not receive a windfall or over-recover production-related costs.

Bias of Resource Decisions

Cities and TIEC argued that providing more favorable rate treatment for purchased capacity relative to installed capacity will adversely bias resource decisions, encouraging utilities to choose purchased power capacity to meet customers' needs even if it is not the most cost-effective or prudent option. TIEC argued that utilities should make resource decisions based on efficiency and prudence, not on rate treatment that arbitrarily favors one decision over another.

SPS stated that TIEC wrongly claims a utility would be encouraged to choose purchased power capacity to meet customers' needs even if it is not the most cost-effective or otherwise prudent option. SPS asserted that if it determines that additional electric power supply resources are required to serve load, SPS will assess the magnitude of resource need, type, and compliance with regulatory requirements. SPS stated that the type of resource that the SPS electric supply system needs is determined through an evaluation of how different resource technologies integrate with SPS's existing electric supply to serve the overall system capacity and energy needs in a least-cost manner. SPS stated further that any resource determination would be reviewed by the commission for prudence, and purchased capacity costs included in the PCRF would be subject to reconciliation.

Commission response

While the commission understands the concern of the parties that a rider for purchased power capacity costs would bias resource decisions in favor of purchased power capacity, regardless of whether it is the most economic choice, the commission believes that the reasonableness and necessity review required as part of the ex-ante review process and the reconciliation of expenses under the rule will avoid such a result. Furthermore, the

commission notes that costs arising from a purchase of capacity are operating expenses of the utility for which no return is earned by the utility. In contrast, a utility is guaranteed a reasonable opportunity to earn a reasonable return on its investment in its own generation facility that is used and useful in providing electric service to the public. No change to the rule is necessary.

Effect of PCRF on Base-Rate Case Settlement

TIEC argued that a PCRF would eliminate black-box rate case settlements for capacity costs and increase the costs and resources required to resolve rate cases. TIEC stated that production capacity costs typically represent 40-60% of a utility's non-fuel costs, and therefore are a contested item in rate cases, and that this litigation has been avoided by black box settlements. TIEC stated that, with a PCRF, a baseline or benchmark must be established to determine includable subsequent increases in a PCRF, and that this requirement would likely prevent black box settlements relative to capacity costs, creating a major impediment to settling rate cases for bundled utilities. TIEC cited this as another example of how the proposed PCRF would likely increase the time and resources associated with utility rate changes, rather than providing any additional efficiency.

In reply comments, ETI responded that parties already routinely stipulate to a number to be used for AFUDC, which has not prevented black box settlements. ETI and SPS asserted that there is no reason to believe that requiring parties to include an agreement on numbers for the PCRF baseline would eliminate the possibility of a black box settlement. SPS stated that baseline values are currently established in settlements for transmission cost recovery factor (TCRF) and distribution cost recovery factor (DCRF) purposes and the need for such baseline PCRF values would not eliminate the ability of parties to agree to a black box settlement.

Commission response

The commission agrees with ETI and SPS that there is no evidence that establishing baseline value components for a PCRF would significantly decrease the likelihood of a base-rate case settlement for bundled utilities. The commission notes that establishing in base-rate proceedings the baseline value components for future TCRF applications does not seem to have greatly hindered parties' ability to arrive at black box settlements.

Commission's Authority to Implement a PCRF

In initial comments, State Agencies stated that PURA does not confer the commission with either express or implied authority to allow the recovery of capacity costs outside of base rates. State Agencies commented that the Texas Legislature (Legislature), by enacting PURA §39.455, provided a strictly limited incremental purchased capacity recovery mechanism that expires on the introduction of customer choice or on the implementation of rates resulting from a PURA Chapter 36 proceeding. State Agencies stated that, through PURA §39.455, the Legislature intended that any such mechanism include an offset for load growth revenues, recognized that PURA did not previously authorize such recovery, and by allowing the limited recovery to expire, the Legislature demonstrated its intent not to allow such recovery past the expiration date.

In reply comments, State Agencies stated that the proposed PCRF rule is arguably contrary to legislative intent.

EPE, ETI, and SWEPCO replied that the commission has clear statutory authority to adopt a mechanism for the recovery of capacity costs outside of base rates. EPE and ETI stated that PURA §36.205 grants the commission clear authority and discretion for crafting a process for the recovery of purchased power capacity costs. EPE argued that the commission's authority to implement a PCRF should be used to improve the model for purchased power capacity cost recovery. SWEPCO stated that PURA does allow for purchased generating capacity cost recovery outside of a base-rate case, and the commission demonstrated in the preamble to the Proposal for Publication that it has the authority to establish and enforce a rule specific to the recovery of purchased power capacity cost. SWEPCO further commented that the Legislature, in PURA §36.204, distinguished purchased power and empowered the commission to "use any appropriate method to provide for the adjustment of the cost of purchased electricity on terms determined by the commission."

Commission Response

The commission agrees with the comments of EPE, ETI, and SWEPCO that it has the statutory authority to implement a purchased power capacity cost rider. The new section is adopted pursuant to PURA provisions of broad applicability including PURA §36.058 which limits the commission's authority to allow the recovery of a payment made by an electric utility to an affiliate and states that such a payment may be included in charges to consumers if there is a mechanism for making the charges subject to refund pending the commission making statutorily-mandated findings regarding the payment; PURA §36.204 which grants the commission the authority to allow timely recovery of the reasonable costs

of purchased power; and PURA §36.205 which permits the commission to use any appropriate method to provide for the adjustment of the cost of purchased electricity that has been accepted by a federal regulatory authority or approved after a hearing by the commission; PURA §36.206 which provides what may be included in a cost recovery factor established for the recovery of purchased power costs, including the cost the electric utility incurs in purchasing capacity and energy. The commission believes these provisions demonstrate that it has the authority to implement a PCRF. Furthermore, the commission notes that PURA §39.455, cited by State Agencies in its initial comments, was adopted by the 79th Legislature as part of a bill of specific, limited applicability that included, for a designated period of time, limitations on a particular electric utility's ability to file a proceeding to change, alter, or revoke rates offered or charged by the utility. Taking into consideration the context of PURA §39.455's adoption, and the provision's placement in a subchapter of explicitly limited applicability, the commission rejects State Agencies' interpretation.

General Comments on the Proposed PCRF

Though the non-utility parties contended that a PCRF rider is not necessary, contingent upon the commission adopting such a rider, they generally supported the proposed PCRF. State Agencies stated that the proposed PCRF has been tailored to allow for extraordinary costs that may be incurred, where the utility must ensure reliability and cannot wait for its next base-rate case to recover costs, and that the proposed rule attempts to contain any broad and open-ended cost recovery. Cities and State Agencies stated that the rule appears to account for load growth and excludes affiliate purchases of capacity. Cities also stated that, while it opposed amending the current PCRF and replacing it with a purchased capacity rider for integrated utilities, the proposed rule adequately avoids incentivizing third-party purchases of purchased power capacity compared to other more economic or beneficial alternatives and reflects changes in other production costs. State Agencies also stated that limiting the PCRF to only third-party contracts is necessary and will avoid the extensive analysis that must otherwise be employed under PURA §36.058 for affiliate transactions. OPUC stated that while a rider for recovery of purchased capacity costs is unnecessary, it believed the proposed rule, with the modifications it recommended in its comments, would strike a good balance among stakeholder interests. TIEC stated that it appreciated the rule's effort to capture the effects of load growth on existing base-rate recovery, and appropriately crediting customers for changes in wholesale sales.

EPE, SPS, and SWEPCO generally supported the objective of the PCRF rule. Though ETI supported the PCRF concept, it argued that, given the proposed rule's load growth adjustment, and the possibility that the utility may need those revenues for reasons other than offsetting additional purchased power capacity costs, the PCRF may be detrimental to a utility's financial situation rather than simply being an efficient means for the recovery of incremental purchased power capacity costs. ETI also stated that the new PCRF rule would make a traditional rate case filing more likely and increase the risk of regulatory lag.

Commission response

The commission concludes that the rule, as adopted, provides for a reasonable balance between the interests and articulated concerns of the affected parties, allowing more timely and extraordinary rate relief to utilities for purchased power capacity costs, while providing safeguards to prevent over-recovery of production-related costs and to encourage cost-consciousness on the part of utilities when making capacity purchases.

ETI-Specific Concerns

Cities raised specific concerns about the effect of a PCRF on ETI.

First, Cities commented that if the commission approves a piecemeal rate recovery mechanism, ETI should be excluded because ETI's current position in the ESA and the uncertainty associated with ETI's exit from the ESA require that capacity costs remain in base rates. Cities stated that ETI has become heavily reliant on capacity received through the ESA at the same time that Entergy Arkansas and Entergy Mississippi have filed notices of withdrawal from the ESA. Cities argued that, as ETI plans for its future capacity needs, it should be required to adhere to the economic incentives provided by the base-rate recovery of capacity costs and not be influenced by any special cost treatment for purchased power capacity costs. Cities stated that because most of ETI's current purchased power capacity comes from affiliates, allowing a true-up of cost recovery would wrongfully allow guaranteed profits and cost recovery for affiliates of ETI. Cities further commented that the majority of ETI's purchase power capacity costs are non-volatile and are solely within the control of ETI and its affiliates.

Cities stated that, since joining the ESA in 1994, ETI has not built any generating facilities. Cities noted that ETI has acquired the right to the output of certain generating facilities through ESA purchase power capacity agreements. Cities stated that ETI has transferred the nominal ownership interest in all its nuclear generation as well as more than half its gas-fired generation to another operating company in the ESA, so that currently ETI relies on ESA purchase power capacity arrangements to repurchase the power and capacity from many of the very facilities it brought to the ESA in 1994. Cities asserted that ETI retains rights to a fixed level of capacity in those transferred facilities through a life-of-unit purchase power agreement (PPA), although ETI's contractual rights to these PPAs may be disputed by the Louisiana Public Service Commission. Cities stated that more than half the capacity of the two gas fired generating stations still owned by ETI is currently committed to another operating company through an ESA purchase power capacity agreement. Cities commented that these decisions regarding ETI's generating capacity should not be influenced by granting ETI special cost treatment for purchased capacity costs, but on the overall benefit for customers.

Cities also commented that ETI's last three rate cases demonstrate that the current regulatory system addresses changing purchased power capacity costs. Cities referred to ETI's 2009 case in Docket No. 37744, in which ETI's initial case requested $250 million in capacity costs through a rate rider mechanism, equal to over a third of the requested base-rate revenue requirement. In addition, Cities stated that ETI requested in rebuttal an additional $20 million annually for purchased power capacity costs that would not become effective until May 2011. Cities stated that the proceeding was settled with a two-step increase in base rates, the first of which was implemented on an interim basis in September 2010 and the second in May 2011, consistent with the addition of new capacity. Cities asserted that the current regulatory model is functional for ETI. Cities commented that, because most of ETI's current purchased power capacity comes from affiliates, allowing a true-up of cost recovery would wrongfully allow guaranteed profits and cost recovery for affiliates of ETI. Cities asserted that a majority of ETI's purchase power capacity costs are non-volatile and are solely within the control of ETI and its affiliates. Cities stated that ETI's recent base-rate case filings demonstrate that base-rate recovery is sufficiently timely to recover costs and that the current regulatory model is functioning as designed. Cities noted that in two of ETI's last three base-rate cases, test year purchased power capacity costs were adjusted for additions scheduled to occur in the rate year or thereafter. Cities stated that in ETI's last base-rate case in Docket No. 39896, ETI requested a rate increase for a plan to acquire additional megawatts of capacity after the test year. Cities stated that, in this case, intervenors showed that if the additional megawatts were priced below ETI's average cost of capacity, and were acquired to serve additional load, then ETI's average or per unit cost of capacity would actually decrease from test year levels, not increase. Cities commented that ETI would be purchasing more megawatts, but the projected purchases were less expensive than ETI's average cost of capacity, and ETI would be receiving more revenues from additional customers and demand that the incremental capacity was intended to serve.

Cities stated that, given ETI's test year installed generation and capacity costs built into customers' rates for the test year load, customer load growth should result in ETI earning revenues that permit it to acquire additional installed generation, generation upgrades, or additional purchased power capacity.

In reply comments, ETI argued that Cities did not explain the connection between the PCRF and the uncertainties, or why the uncertainties mitigate the harsh impacts of the current ratemaking model. ETI asserted that the uncertainties surrounding the continuation of the ESA provide a strong argument for ETI to have access to a PCRF. ETI argued that it will need more ratemaking flexibility if the ESA terminates, so customers can receive the benefits of purchased power and the company can timely recover the costs of that power. ETI argued that, in the absence of the ESA, ETI will be contracting, at least in the short term, for the same, if not a greater, amount of purchased capacity.

In reply comments, ETI further stated that because there is typically no temporary excess capacity under the purchased power model, the incremental cost of capacity used to serve load growth does not always or typically fall below average embedded costs, as is the case with new utility-owned generation built with lumpy invested capital, but rather incremental capacity costs typically remain above embedded costs year in and year out. ETI stated that, meanwhile, in a rising cost environment, the utility needs load growth revenues to offset the rising costs of its administrative, operations, maintenance, and capital needs. ETI argued that, though it is possible for a utility that self-builds a new power plant to enjoy a period of declining capacity cost and possible short-term and limited increased earnings because of load growth, that result is very unlikely for a utility relying on purchased power capacity because load growth will necessarily have to be served by constructing a new power plant or obtaining a new purchased power agreement, neither of which is reflected in rates absent a PCRF or another rate case.

ETI stated that, perhaps because of different markets, EPE, SPS, and SWEPCO are building power plants to meet their resource needs, and therefore do not have significant amounts of purchased capacity in base rates, unlike ETI. ETI asserted that the commission is aware of the build-out of the independent generation in ETI's market and the resulting availability of reasonably priced purchased power. ETI stated that it has contracted for large amounts of such power, on which it does not earn a return, with fuel savings for customers and capacity costs that do not reflect lumpy, over-sized investments in power plants. ETI stated that, over the course of ETI's current fuel reconciliation period, the expected fuel cost savings from two of its new purchased power contracts are estimated to be $78 million, more than the capacity costs of the contracts, but only a small portion of the capacity cost of one of these contracts is currently in ETI's rates. ETI stated that, in an effort to obtain earnings relief, it filed its most recent rate case, the result of which is that only a small portion of one purchased power contract went into rates because its other contracts were not in place throughout the test year. ETI stated that, while its customers benefit from the contracts, its earnings have been worse even after three recent rate cases in the past six years because the capacity costs of the contracts are not fully in rates.

Commission response

The commission concludes that a PCRF rider should be made available for all vertically integrated electric utilities. The commission declines to adopt a provision that would specifically exclude any particular electric utility from seeking to establish a PCRF. This rule is intended to be generally applicable; any electric utility may apply, in conformance with the provisions of the rule, to establish, adjust, or terminate a PCRF. The calculation of the PCRF rates under the rule, in allowing for historical recovery of costs in excess of

production-related base-rate revenues is expected to provide for more timely recovery of capacity costs, while preventing over-recovery of such costs, across a variety of possible outcomes for ETI as well as other vertically integrated electric utilities.

Section 25.238; Purchased Power Capacity Recovery Factor (PCRF)

Subsection (a); Application

No comments.

Subsection (b); Definitions

No comments.

Subsection (c); Establishment, adjustment, and termination of a PCRF

Subsection (c)(2)

Affiliate Transactions

OPUC opined that the exclusion of affiliate purchases in the proposed rule is appropriate, given the nature of affiliate transactions and the special treatment of affiliate costs, which is dictated by statute and case law. OPUC argued that compared to market-based transactions, affiliate transactions require additional scrutiny to ensure that the utility has not engaged in self-dealing, and that this process is best undertaken in a base-rate proceeding, particularly considering that the proposed rule would process the PCRF application in an already compressed schedule.

SWEPCO stated that, to the extent that capacity purchases from affiliates are under a FERC-approved agreement, the commission should allow the inclusion of such costs in a PCRF rider.

SWEPCO stated further that if capacity from an affiliate is purchased through a competitive solicitation process in which third parties are also bidding, these costs should be allowed. SWEPCO agreed that company-owned capacity should not be a component of the PCRF as outlined in paragraph (2)(B).

Commission response

For the reasons mentioned previously, the commission declines to exclude purchases of capacity from an affiliate; instead, the commission adopts a process wherein a utility may seek commission review and approval of an arrangement for the purchase of capacity from an affiliate such that thereafter the utility may seek to include such an approved purchase in the PCRF. The commission also declines to adopt SWEPCO's suggestion that certain affiliate-related purchases should be deemed allowable without further review, as discussed previously. The heightened standard for review of affiliate-related expenses requires a more thorough examination of payments made to an affiliate, including those for the purchase of capacity.

Subsection (c)(3)

Demand Ratchet

SWEPCO argued that the proposal to prohibit the use of a demand ratchet mechanism for billing the PCRF creates a second, shadow billing scenario. SWEPCO explained that a demand ratchet is a means of applying a minimum billing to a customer who may have inconsistent or seasonal energy requirements. SWEPCO stated that the minimum monthly billing is calculated based on a given percentage of a customer's peak use, even if little or no energy is used during a particular month, which ensures that the utility is properly compensated for the year-round costs it incurs to serve the customer. SWEPCO stated that, given that demand is the primary driver for capacity needs, special consideration for demand-billed customers is not warranted.

Commission response

The commission is persuaded by SWEPCO that the use of a demand ratchet mechanism may be appropriate on a case-by-case basis, given the nature of capacity costs. Accordingly, the commission modifies subsection (c)(3) of the published rule to remove the prohibition on the use of a demand ratchet mechanism in collecting charges under the PCRF.

Subsection (c)(5)

Concerns Regarding Feasibility of Termination

ETI argued that the uncertainty in the proposed rule with regards to terminating a PCRF will deter utilities from requesting a PCRF, and should be modified to provide greater certainty with regard to the path for termination. ETI stated that the proposed rule penalizes a utility that wants to increase its investment in affiliate and self-owned generation, as compared to third-party purchases, unless and until the utility can persuade the regulatory authority to allow it to withdraw the PCRF tariff. ETI argued that the proposed language that the utility “may request” termination implies that the commission could deny that request, though it was unable to identify any possible situation in which the commission would deny a request to terminate a PCRF. ETI stated that, while there may be suspicion that a utility may “game” the system and receive a windfall, it is improbable that there would ever be a gaming opportunity given that the PCRF is intended to be an incremental cost recovery mechanism over costs already in base rates, as the elimination of the PCRF simply removes the incremental cost recovery. ETI stated that it would only be the circumstance where the load growth adjustments are greater than the PCRF costs, resulting in the PCRF being a refund factor instead of a recovery factor. ETI argued that reducing approved base rates for load growth revenues was clearly not the intended purpose of the PCRF, so allowing the utility to terminate a PCRF in those circumstances is reasonable. ETI proposed language to allow the utility to terminate its PCRF if it so desires.

In reply comments, EPE and SWEPCO agreed with ETI. SWEPCO asserted that if a capacity purchase agreement expires, the utility should not need permission to discontinue the incremental cost recovery factor application. SWEPCO suggested that a final order would not be necessary for the utility to discontinue the rider; rather, within 45 days of discontinuing the PCRF, the utility should be required to file an application for final reconciliation of the costs and revenues associated with the terminated PCRF. EPE argued that, because a PCRF is a voluntary process for the purpose of recovering incremental purchased power capacity costs, the utility should be able to terminate the PCRF when it no longer sees a need for it.

Cities argued that ETI's proposed change would make the rule one-sided where customers' rates would increase if the unit cost of capacity were to increase, but rates would not decrease if the unit cost of capacity were to decrease. Cities stated that if a utility elects to implement a PCRF during a time of increasing costs, it should not be permitted to unilaterally terminate a PCRF if it were to appear customers' rates would be reduced due to decreases in costs.

Commission response

The commission agrees with the general concern expressed by ETI, EPE, and SWEPCO that requiring commission approval to terminate a PCRF might introduce risk to a utility that chooses to establish a PCRF. Further, the commission notes that the new subsection (c)(1)(C) and (D) serve the purpose of addressing potential "gaming" concerns with respect to the timing of PCRF establishments and terminations. With respect to Cities' concern regarding the one-sided nature of allowing utilities to terminate a PCRF without the need to seek commission approval, the commission concludes that, along with the new subsection (c)(1)(C) and (D), it is appropriate to limit a utility's ability to terminate its PCRF to only once a year, as part of the annual PCRF adjustment proceeding. Permitting a utility to terminate its PCRF at its own discretion, but limiting such termination to once a year, in an annual PCRF adjustment proceeding, strikes a reasonable balance in addressing parties' respective concerns. Subsection (c)(5) of the rule is therefore modified accordingly.

Subsection (d); Notice of a PCRF proceeding

No comments.

Subsection (e); Procedural schedule

SWEPCO recommended striking the phrase "except where good cause supports a different procedural schedule," asserting that this language may unnecessarily invite parties or a presiding officer to depart from the established procedural schedule in the rule. SWEPCO argued that 90 days is ample time because of the scope of the application to adjust the PCRF is very limited and is subject to review in a fuel reconciliation proceeding, and that a longer schedule is not necessary and may encourage unnecessary litigation.

Cities and TIEC recommended rejecting SWEPCO's proposed 90-day schedule. Cities responded that at the same time SWEPCO proposes to shorten the 120-day review into 90 days, it also proposes to insert the two inherently contentious issues of affiliate transactions and projected capacity costs into PCRF proceedings. TIEC argued that a procedural schedule of 90 days is entirely insufficient to examine new purchased capacity costs, much less the other types of issues the utilities are seeking to inject into the PCRF cases. TIEC stated that the 120-day schedule in the proposed rule is already an abbreviated procedural schedule if a hearing is requested. TIEC stated that requiring parties to process a PCRF proceeding from start to finish in three months is unworkable and will significantly prejudice customers' interests, particularly if any of the utilities' over-reaching requests are granted, like the proposal to use projected costs or make known and measurable changes to the historical test year costs. Cities noted that SWEPCO does not claim that an abbreviated review schedule is necessary to timely implement a change in PCRF rates.

Commission response

The commission agrees with the recommendation of Cities and TIEC to reject the proposal of SWEPCO to reduce the timeframe to 90 days. The commission believes that the 120-day deadline provides sufficient time for parties to review the PCRF and also ensures timely recovery of purchased power capacity costs for utilities. In addition, the commission rejects SWEPCO's proposal to strike the language "except where good cause supports a

different procedural schedule," as the commission wishes to retain the ability to modify the procedural schedule as necessary, especially given that there is no prior experience for a PCRF proceeding of this kind. The commission does not believe that this good cause exception will unnecessarily encourage parties to extend the procedural schedule.

Subsection (g); PCRF Formula

Subsection (g)(1)

Use of a Historical Cost Year

EPE and SWEPCO stated that the proposed rule bases the PCRF on a "cost year," which the rule defines as the "most recent historical 12-month period for which data are available at a time a utility prepares an application to establish, adjust, or terminate a PCRF." EPE and SWEPCO noted that the proposed rule does not seem to contemplate updating the historical period, and will result in a new PCRF reflecting unadjusted costs incurred 6-18 months prior, not costs expected to be incurred during the time the PCRF is in place. ETI argued that this lag occurs though fuel savings are immediate. SWEPCO stated that the PCRF will always significantly lag actual cost and create distorted price signals to the customers concerning actual purchased capacity costs being incurred on their behalf.

EPE, ETI, SPS and SWEPCO argued that the PCRF should be modeled after fuel, which is set to recover projected costs, to more closely track purchased capacity costs. EPE, ETI, and SWEPCO argued that the costs and revenues will be subject to later reconciliation, and both the customers and utility will be protected and will benefit from timelier matching of capacity costs with actual expense. ETI argued there is no reason to assume that purchased power capacity costs would be any different from fuel costs, which notably include purchased energy costs. ETI noted that the fuel rule's use of projected costs in setting a fuel factor has not led to excessive litigation as TIEC argued in its comments on the commission's straw man rule.

Cities, OPUC, and TIEC supported the proposed rule's use of historical costs and opposed utilities' suggestion of using projected costs. Cities and TIEC asserted that the commission should maintain the use of actual cost year production costs instead of estimated or projected capacity costs, which will reduce the likelihood that the PCRF will significantly over- or under-recover actual costs, helping to mitigate the rate volatility and significant reconciliation that are likely to result from the proposed rule. Cities stated that fuel is traded on the public market, and estimated future fuel futures are published and can be readily verified, unlike capacity costs. Cities, OPUC, and TIEC stated that the use of estimated future capacity costs would unnecessarily complicate the rule and undermine the alleged benefits of providing updates in a streamlined process by interjecting contentious issues.

OPUC argued that the proposed PCRF already reduces regulatory lag, as it allows the utility to obtain interim relief between base-rate cases. OPUC stated that capacity costs embedded in base rates are based on the amount of costs observed during the historical test year used in the utility's last base-rate case, and it follows that an incremental capacity costs recovery mechanism such as the PCRF should measure costs in the same way as the capacity costs embedded in base rates.

TIEC argued that the purpose of the rule is to allow for recovery of incremental purchased power costs between rate cases, not to provide a revenue stream for projected purchased power capacity costs before they are even incurred. TIEC stated that allowing utilities to project their purchased power costs and begin collecting those costs in advance significantly reduces the utility's incentive to minimize overall costs in a given year to maximize its return. TIEC stated that this will harm ratepayers, is inconsistent with the fundamental ratemaking principles, and that PURA and the commission's rules generally require use of historical data except in very few, limited cases. TIEC noted that fuel costs have historically been treated differently than base-rate costs, such as purchased power capacity, because of their extreme volatility and the need for interim adjustments to mitigate the rate impacts of this volatility. TIEC argued that utilities have less ability to control fuel costs than purchased power capacity agreements, and do not have the same type of options for avoiding those costs, such as building or expanding installed generation resources). TIEC also noted that the reasons that may justify using projected costs in the few limited circumstances that the legislature and the commission have explicitly authorized in the past simply do not exist for purchased power capacity costs. TIEC argued that purchased power capacity costs should be examined over a historical test year for purposes of the PCRF, as other base-rate costs are.

TIEC stated that the commission should reject the utilities' proposal to alternatively permit known and measureable changes to historical test year costs. TIEC stated that determining whether a given cost adjustment is "known and measurable," rather than projected, is subject to a body of precedent and is often a hotly contested item in rate cases. TIEC observed that ETI recently sought more than $30 million in purchased power capacity costs that it claimed were "known and measurable" in Docket No. 39896, but the commission disagreed that these costs met the applicable standard and disallowed them. TIEC stated that relying on historical test years appropriately protects consumers from unjustified costs, maintains utilities' incentive to reduce overall costs, and is consistent with the way other non-fuel expenses are treated.

Commission response

The commission agrees with the comments of Cities, OPUC, and TIEC that historical cost recovery is appropriate for purchased capacity expenses. Traditionally, recovery of capacity expenses has been set based upon a utility demonstrating its historical, actual capacity costs and the commission is not persuaded that it is appropriate to change this long-standing practice. Furthermore, as discussed previously, maintaining some regulatory lag provides an incentive for utilities to prudently manage expenses incurred in purchasing power capacity. Using historical costs also minimizes over- or under-recoveries and avoids the unnecessary controversy in PCRF proceedings that would result from using projected, rather than actual costs. The commission declines to modify the rule in this respect.

Ambiguity of True-up Language

ETI stated that, should the commission decline to set a PCRF based on projected costs, the commission's use of "cost year" could suggest that the cost year must be matched with corresponding revenues in a reconciliation, resulting in an approximately 18 month delay between the historical cost year and the time the factor to recover that historical cost year is in place, without any compensation for the time value of money. ETI argued that is not appropriate to build regulatory lag in a pass-through process, suggesting that the ambiguity could either be removed by changing the formula to recover projected costs, or rewording the formula to allow for known and measurable changes to the cost year purchased power capacity costs and rewording the reconciliation provision to make clear that the intent is to match actual costs to actual revenues. ETI proposed modified language to this effect in subsections (g) and (j) consistent with its discussion.

Commission response

The commission declines to adopt ETI's recommendation to add language allowing for known and measurable changes to capacity purchases tracked through a PCRF or to allow for contemporaneous recovery of purchased capacity expenses, for the reasons previously mentioned regarding regulatory lag. The true-up provision of the rule provides for a method of collecting or refunding any differences between actual PCRF revenues collected and the revenues that the PCRF was set to collect. The purposes of the reconciliation proceeding are to examine the reasonableness, necessity, and prudence of the expenses included for recovery in the PCRF; to determine any disallowances or other appropriate adjustments that may be reasonable; and to ensure that the revenues recovered under the PCRF appropriately match the reasonable, necessary, and prudent PCRF expenses.

TIEC's Proposed Modifications to the Formula

TIEC stated that it generally supported the proposed PCRF formula, with a modification. TIEC asserted that the formula may result in significant rate volatility as a result of being calculated on a class-by-class basis. TIEC stated that, if a specific customer class experiences significant changes in billing determinants because of extreme weather, economic conditions, or other factors that may be unique to a specific customer class, this can cause extreme volatility in the

PCRF for that class under the proposed formula. TIEC proposed instead to calculate and track the PCRF on a system-wide basis in a fashion similar to base rates. TIEC recommended that the system-wide revenue requirement and required increase be determined, and then the increase allocated to the classes and a rate derived. TIEC argued that using system-wide rather than class-specific costs to calculate the PCRF will require fewer inputs, resulting in a formula that is simpler and easier to administer. TIEC argued that the true-up process would also be less volatile because it would reflect system-wide variances between actual and projected usage level rather than on a class-by-class basis.

In reply comments, State Agencies argued that it is not reasonable to set up a cost recovery formula that imposes such uneven rate impact among classes, given that additional capacity is often acquired to serve load growth. State Agencies asserted that classes with lower load growth should not be responsible for more of the increased costs than customers in the classes with larger load growth, for whom the additional costs may have most likely been incurred. State Agencies stated that it believed TIEC's proposed alternative formula would help mitigate this concern, with a correction to a small error it noted. ETI and State Agencies noted an error in the term "$\%GROWTH_{CLASS}$" and that this term may be intended to reflect system growth, not growth for each class, and should be "%GROWTH" and represent $(BD_{CY}-BD_{RC})/BD_{RC}$, the percentage growth in billing determinants for the entire system.

ETI stated that TIEC's proposed formula has a compounding effect that will result in an unjustified load growth adjustment. ETI stated that it does not object to the other aspect of TIEC's proposed adjustment, which allocates the net system true-up adjustment based on cost year allocations, rather than a class-by-class basis true-up, so long as other parties are agreeable to smoothing out the impact of sales fluctuations by some classes subsidizing other classes with regard to their contribution to load growth-adjusted capacity costs considered recovered under existing base rates. SWEPCO stated that because this aspect of TIEC's formula is a reallocation of total costs among classes for the policy reason of mitigating the impact on individual classes, it does not have a strong objection, though it does not find TIEC's justification persuasive and believes that cost causation principles call for rejection of this aspect of the formula.

A majority of other parties opposed TIEC's proposed modification to the formula. EPE replied that the commission should reject TIEC's proposed changes. EPE and ETI noted that TIEC's proposed alternative introduces terms that are not defined in either the original commission proposal or by TIEC: PPC_{RC}, $APC_{RC,}$ and TU have no definition, and the new term $\%GROWTH_{CLASS}$ is defined using the undefined terms $BD_{CY\text{-}CLASS}$ and $BD_{RC\text{-}CLASS}$. EPE stated that, moreover, the consequences of TIEC's proposed application of cost year allocations both to the true-up adjustment and to the calculation of the growth adjustment have not been fully explained by TIEC, nor have other parties had ample opportunity to examine them. EPE stated that it has concerns that TIEC's formula may improperly account for changes in revenues because it applies updated allocation factors to historical growth rates.

SWEPCO stated that TIEC's formula also determines the billing determinant adjustment for each class by starting with the system, rather than the class, embedded capacity costs and then adjusting the system total for the change in billing determinants experienced for the individual class, and then adjusting that total to a class level by multiplying the cost year, rather than last rate case's allocations, resulting in the formula overstating the billing determinant adjustment. SWEPCO stated that this is because by allocating based on cost year billing determinants, the class with greater growth will have a greater cost year allocation with the result that the growth for that class is overstated. SWEPCO noted that, in contrast, the commission's proposed formula determines each class' billing determinant adjustment by using allocations from the utility's last rate proceeding, so each class' calculated adjustment is the actual change in billing determinants for that class since the last rate case.

Cities and OPUC opposed TIEC's proposed modification to calculate a system-wide rate adjustment instead of a class-specific adjustment. Cities and OPUC asserted that TIEC's proposal does not properly match the cost incurred to the customers causing the costs to be incurred or the revenues collected to the customers paying those revenues, thus violating cost causation. OPUC argued that the increase in capacity-related base revenue resulting from load growth is known with certainty on a class-by-class basis, but TIEC's proposal ignores the values and replaces them with proxies that result from use of an allocation factor. OPUC asserted that TIEC's approach socializes the incremental revenue resulting from load growth and results in an inappropriate cross-subsidization among rate classes, resulting in some classes subsidizing other classes to their detriment. OPUC stated that, because the load growth adjustment in TIEC's proposal is subsumed in the increased revenue to be recovered through the PCRF, the revenue effect of load growth is being allocated to rate classes. Cities noted that the system-wide adjustment proposed by TIEC will not accurately reflect revenues for customers as some customer classes are billed on a demand basis and some classes are billed on an energy basis. OPUC argued that, in ETI's most recent base-rate case, the commission found that rates should be brought to cost unless the change would result in rate shock. OPUC further argued that, as the PCRF contains only incremental capacity costs, it would form a relatively small portion of the bill and fluctuations in the PCRF would not be large enough to warrant TIEC's suggested moderation techniques.

Commission response

The commission rejects TIEC's proposed modifications to the formula, on the basis of cost causation, as well as other concerns relating to mathematical errors and undefined terms. The commission agrees with the comments of Cities and OPUC that TIEC's approach does not accurately reflect revenues on a class-by-class basis, socializes load growth revenues when the revenue is known with certainty on a class-by-class basis, and that the PCRF is not likely to be such a significant portion of the customer's final bill as to warrant the volatility and rate shock concerns that would support TIEC's proposed approach. In response to the comments of State Agencies, the commission would note that, while classes with relatively less load growth would see less of a revenue offset to incremental capacity costs, the use of an updated cost-year allocation factor should result in relatively fewer costs allocated to such classes in the first place, thus mitigating the lesser load growth revenue offset.

OPUC's Proposed Modifications to the Formula

OPUC argued that because the cost of capacity purchases is included in the test year cost of service used to set base rates, a portion of the revenue stream created by base rates is designed to recover the cost of capacity purchases. OPUC noted that this revenue stream typically increases over time as the utility's sales increase. OPUC stated that, because the PCRF is designed to collect incremental capacity costs, it must also recognize incremental capacity-related revenue to avoid structural over-recovery, and it therefore supported the inclusion of a load growth adjustment in the PCRF formula.

OPUC noted that the adjustment in the formula, however, is not limited to load growth, because the adjustment factor could take a value less than one, and thus the formula would also account for revenue decline. OPUC argued that, under this version of the formula, even a utility with no increase in capacity costs could obtain additional revenue through the PCRF, essentially resulting in a lost revenue mechanism. OPUC stated that this can be corrected by changing the (CBD_{CY}/CBD_{RC}) term to MAX[(CBD_{CY}/CBD_{RC}), 1], which would account for the effect of load growth on the recovery of purchased capacity costs through base rates while preventing the use of the PCRF to recover any decline in base-rate revenue that may occur. OPUC also noted that the formula makes a second load growth adjustment to reflect the effect of increased sales on revenue related to depreciation, taxes, and return associated with embedded production capacity, and that to ensure that the adjustment only reflects load growth and not decline, the term ((CBD_{CY} – CBD_{RC}) / CBD_{RC}), which is the ratio of the increase in billing determinants to the billing determinants used in setting base rates, should be changed to MAX[((CBD_{CY} – CBD_{RC}) / CBD_{RC}), 0]. OPUC stated that, given these two changes to the formula which would preclude a utility from obtaining recovery of lost revenue, OPUC would support a load growth adjustment in the proposed rule. State Agencies agreed with OPUC that the proposed formula should not function as a lost revenue recovery mechanism for utilities.

SWEPCO stated that OPUC's concern is that a utility may have a period of declining sales resulting in the billing determinant adjustment being negative, which would increase, rather than decrease, the PCRF factor. ETI and SWEPCO stated that this result is logical; if a load growth adjustment is appropriate to account for additional revenues, then that same adjustment mechanism is only fair to account for load declines that would mean a shortfall in contribution to capacity costs. SWEPCO stated that if negative growth presents a problem, the proper solution is to remove the billing determinant adjustment altogether.

Commission response

The commission adopts both modifications recommended by OPUC. Subsection (h)(1) is modified accordingly. The commission agrees with OPUC that the PCRF should not function as a lost revenue adjustment mechanism, but instead should only recover incremental purchased power capacity costs in excess of production-related load growth revenues. The commission rejects the arguments of ETI and SWEPCO, because an increase in revenue for capacity when the utility is experiencing load loss would result in an undue windfall to the utility. In particular, the commission notes that the utilities have generally argued previously that purchased power capacity is an expense, an argument with which the commission agrees. When no expense is incurred by the utility for purchased power capacity beyond that in base rates, there is no need to recompense the utility for that expense through the PCRF rider. Further, the commission notes that, pursuant to subsection (c)(5) of the rule, a utility may elect to terminate its PCRF in its annual PCRF proceeding, and that a utility is also free to apply for a base-rate increase in the event that it is suffering revenue shortfalls resulting from loss of load.

General Comments on the Formula's Proposed Load Growth Adjustment

ETI stated that commenters ignore the fact that, while it is possible that increased revenues from load growth can lead to improved earnings, this typically happens in the period immediately after a rate case, especially one after a large solid fuel plant goes into rate base, and thus in a situation where a utility has excess capacity. ETI argued that purchased capacity costs are fitted to a capacity need at a certain point in time, and that, unlike with a new plant, there is little danger of excess capacity after the purchased power contract goes into rates. ETI stated that, with no excess capacity, incremental capacity costs will remain significant, resulting in ETI's poor earnings even immediately after new rates are implemented. ETI argued that, in the case of newly built power plants, regulatory lag can financially harm the utility, but the utility can sometimes achieve reasonable returns after the plant goes into rate base if the utility's incremental capacity costs are low because of temporary excess capacity, and load growth is strong. ETI asserted that the utility that relies on purchased power sized to fit its needs cannot catch up in rate cases until it has excess capacity. SWEPCO asserted that removing the billing determinant adjustment altogether will prevent the results that the utilities and OPUC find untenable.

ETI and SWEPCO argued that the proposed rule's load growth adjustment is overly broad and inappropriately calls for the calculation of additional revenues associated with the utility's installed capacity, and then uses those revenues as an offset against additional capacity costs. ETI and SWEPCO stated that the proposed rule's load growth adjustment ignores the fact that the utility may be applying revenues to cover the cost of additional capacity under construction or additional investment in existing capacity, and would deprive utilities of revenue. SWEPCO requested that the commission further consider the potential detrimental impacts of the load growth mechanism on the utility's ability to invest in its infrastructure. SWEPCO stated that it has significant generation included in rate base, and the formula is inconsiderate of a utility's investment in its generating plants. ETI argued that the proposed load growth adjustment is unnecessary.

ETI and SWEPCO argued that the formula can become a rate reduction rider by adjusting rates downward in response to growth without any change in purchased capacity costs, and can potentially go to zero. ETI argued that if a utility ceases to enter into new third-party contracts or reduces purchases of third-party power, and instead turns to affiliate, self-build, or life extension generation projects, then the PCRF will cause utility revenue to fall, even if purchased power capacity purchases are flat, because load growth will continue. SWEPCO argued that the idea of a growth adjustment was to offset additional purchased power costs by capturing what were considered associated revenues, not to provide a rate adjustment mechanism for changes in revenues. ETI argued that this artificially driven revenue reduction, which occurs even if third-party power purchase costs are not declining, may occur at precisely the time the utility needs load growth revenue to support better options that involve capital investments or more economical purchases from affiliates. ETI stated that it supports a decrease in the PCRF rates should incremental purchased power capacity costs turn flat or fall. ETI stated that while it does not believe the load growth adjustment is appropriate, the proposed rule overreaches in its reduction for revenue growth beyond revenue growth attributable to third-party purchased power contracts to include the load growth for all generation functions.

ETI also stated that, because utilities dispatch their most efficient units first, the variable costs of production for sales on the margin are more expensive to produce than those on average, so the revenues from additional sales will necessarily contribute less to the fixed capital costs as compared to the revenues on average. ETI argued it is erroneous to assume that each dollar of load growth will have the same proportion available to contribute toward capacity cost as was available on average when rates were set. ETI stated that, with respect to the proposed rule's formula that requires all the additional revenues be applied against purchased capacity costs, it fails to recognize that a utility may be serving additional load by means other than purchasing capacity, such as system expansion or upgrades. ETI argued that the proposed rule's load growth adjustment does not allow those dollars to be available for such upgrades.

ETI stated that the formula could discourage the utility from adopting the PCRF mechanism because of its potential to starve the utility of revenues it needs not only to execute self-build options, but revenues it has historically used to support capital additions for legacy and affiliate units in need of environmental compliance, overhauls of equipment, and generation life extensions. ETI proposed revisions to subsection (g)(1) consistent with its comments.

Cities and TIEC argued that the rule should not be designed to recover incremental production capacity costs without reflecting the incremental production cost revenues associated with load growth. Cities and TIEC stated that if a utility makes additional capital investments, it can file a base-rate case if it believes it needs to increase rates above what can be accomplished through a PCRF. Cities asserted that the current rule as proposed by the commission properly offsets the cost of incremental third-party capacity purchases with the incremental production related revenues that would be recovered by the utility for serving the incremental load.

TIEC responded that there is no requirement that a utility use additional base-rate revenues from installed generation to make additional capital investments. TIEC argued that assuming that this will always be the case would bias the rule in favor of utilities and unduly harm customers. Cities and TIEC stated that if the rule does not include base-rate revenues associated with installed generation capacity, the utility could simply pocket these generation-related revenues and then seek incremental recovery of any new purchased power costs, though the increased revenues could be sufficient to recover the costs of increased capacity. TIEC asserted that sources of generation capacity are fungible, contrary to ETI's arguments, and therefore revenues from the base rates associated with these resources should be treated as fungible. TIEC argued that customers should at least be given the minimal protection of receiving credit for all additional load growth revenues from any generation-related costs in base rates before a PCRF rate increase occurs.

TIEC stated that ETI's and SWEPCO's arguments highlight a fundamental problem with the PCRF that warrants its rejection altogether. TIEC asserted that ETI and SWEPCO are essentially complaining that the proposed PCRF cannot consider changes in generation investment. TIEC noted that when installed generation costs decrease, a utility would still be able to increase rates through the proposed PCRF without crediting customers for these reduced costs. TIEC reasserted its prior comments that a utility could sell a generating plant, keep the proceeds, replace that capacity with a new non-affiliate purchased power agreement and recover the additional costs of the contract through the PCRF, resulting in an extreme over-recovery. TIEC argued that the inability to consider changes in generation costs in a PCRF results in a high likelihood that the PCRF will cause utilities' rates to be out of line with their overall generation costs. TIEC stated that this undesirable dynamic does not support further harming consumers by ignoring load growth revenue associated with capacity sources other than non-affiliate contracts. TIEC stated that, since this issue cannot be adequately addressed in the proposed PCRF, it justifies rejecting the PCRF rule outright. TIEC argued that if the PCRF is adopted despite this serious flaw, customers should be protected by using all additional generation-related revenues to offset additional purchased capacity costs before a PCRF increase is approved, as in the proposed rule.

TIEC reasserted that it has become a well-established and accepted requirement at the commission that additional base-rate revenue from load growth must be taken into account before a utility can increase rates to recover any related incremental costs. TIEC stated that ETI previously petitioned the commission for a PCRF rule that did not include a load growth adjustment, and the commission rejected ETI's proposal in part because the rule did not adequately address the role of load growth in the determination of a PCRF. TIEC commended Staff for addressing this issue in the proposal for publication and stated that it opposed ETI's and SWEPCO's proposal to eliminate the load growth adjustment or limit it to a subset of generation-related costs.

Commission response

The commission appreciates the comments of the parties. The commission retains the load growth adjustment in the proposed rule. The load growth adjustment contained in the adopted rule is intended to strike a reasonable balance between the concerns raised by TIEC regarding the potential for over-recovery, the fungibility of production sources, and the advantages of examining all of a utility's production-related expenses *in toto* on the one hand, and the issues raised by ETI and SWEPCO on the other, such as desires for a reduction in regulatory uncertainty, a more streamlined PCRF process, and more timely recovery of costs incurred in the provision of electric service. As stated previously, striking a reasonable balance between such occasionally competing interests is difficult; therefore, the commission intends in two years to review the operation and parties' use of the rule to determine whether provisions of the rule, including the load growth adjustment, should be reevaluated. The commission also agrees with TIEC that it has included adjustments for load growth in other recent rulemakings, Project No. 39465, *Rulemaking Related to Periodic Rate Adjustments*, and Project No. 39674, *Rulemaking Proceeding to Amend Energy Efficiency Rules*. The commission notes that establishment of a PCRF is voluntary; the utility may annually determine whether it is appropriate to terminate its PCRF; and a utility retains the ability to seek an adjustment to its base rates for circumstances that include a reduction in load growth.

Subsection (h); True-up

No comments.

Subsection (i); Off-system sales

The utilities generally opposed the proposed rule's requirement that utilities credit 100% of the margins from off-system sales to customers. EPE stated that TIEC's and OPUC's arguments, regarding a prior straw man proposal, that 100% of off-system sales should be credited to customers because generation is included in rate base and such sales have been traditionally treated that way, were not completely accurate. EPE stated that off-system sales may well occur from capacity that is not in rate base. EPE stated that an arbitrage situation could occur where a utility purchases less expensive local capacity and sells capacity from the utility's remote generation at a higher price. EPE noted that, in that case, the generation that makes the sale possible is not in rate base. EPE argued that, similarly, a utility may have an opportunity for off-system sales from a generation new plant not yet included in rate base. EPE stated that the commission in the past has allowed sharing of off-system capacity sales, and cited as examples Docket Nos. 27035 and 32289. EPE argued that the commission's rules expressly allow sharing of margins on energy sales without restriction on whether the energy was generated by the plant in rate base. EPE argued that if TIEC's arguments are followed to their logical conclusion, then sharing of margins from sales of energy generated by those same plants should not be allowed either; but contrary to this, the commission recognized the merit of encouraging utilities to make off-system sales when it adopted the rule providing for the sharing of energy sales margins. EPE asserted that customers are better off when the utility is encouraged to seek out opportunities that could lower customer costs, and that is true whether the sale is energy or capacity. EPE recommended that the provision be revised to parallel provisions in the fuel rule at P.U.C. SUBST. R. §25.236(a)(7).

SWEPCO stated that in Docket No. 32898, the commission found it proper to credit capacity auction revenue as an off-system sale. SWEPCO further commented that P.U.C. SUBST. R. §25.236(a)(8) allows a utility to retain 10% of its off-system energy sales margins, in order to encourage a utility to take advantage of market situations that may benefit customers. SWEPCO argued that the same logic is appropriate for sales of capacity.

In reply comments, TIEC stated that ratepayers should receive 100% of the margins from off-system capacity sales. TIEC asserted that allowing utilities to charge ratepayers for 100% of a purchased capacity contract and then retain 10% of any profits from re-selling power under such a contract creates an arbitrage opportunity. Furthermore, TIEC commented, such a treatment would not be consistent with the way base rates are set. TIEC noted that, in a comprehensive rate case, a utility's purchased capacity costs are reviewed in conjunction with changes in the level of revenues from wholesale sales of electricity. TIEC stated that, through this review, retail/wholesale jurisdictional allocation factors are developed that give Texas retail ratepayers the benefit of 100% of the margins from off-system capacity sales. TIEC noted that, generally, utilities have only been allowed to keep revenues from off-system capacity sales when increased wholesale sales occurred outside a rate case test year.

Commission response

The commission agrees with the comments of TIEC that allowing for the sharing of margins from capacity sales would create an inappropriate arbitrage opportunity wherein the risks and costs of a capacity purchase are borne entirely by ratepayers while the utility captures a portion of any rewards. The commission also notes that, with respect to

margins realized from opportunity sales of capacity, the small amount of regulatory lag present in the rule works to the benefit of the utility and provides an incentive for the utility to realize such sales when they are economical. The commission declines to adopt changes to the requirement that 100% of capacity sales margins be returned to ratepayers via the PCRF.

Subsection (j); Reconciliation of PCRF Expenses

ETI proposed modifying the language to make clear that the reconciliation is between the actual incurred cost and the actual revenues. SPS commented that it supported this modification.

Cities recommended rejecting ETI's proposal that the commission clarify that PCRF revenues are reconciled to the capacity expenses incurred. Cities stated that ETI's proposal should be rejected as the commission's proposed rule already permits the reconciliation of PCRF revenues to actual costs incurred. Cities stated that ETI's proposed modification is another attempt to remove load growth from the proposed rule, as the modification does not account for load growth revenues that would already recover a portion, if not all, of the capacity costs incurred. Cities noted that the proposed rule already permits the recovery of actual costs incurred during the cost year in each annual PCRF adjustment.

Commission response

The commission agrees with Cities that ETI's proposed modification would inappropriately remove load growth and the historical cost recovery from the rule, and declines to adopt ETI's recommendation to add language allowing for known and

measurable changes or to allow for contemporaneous recovery of purchased capacity expenses, for the reasons previously discussed. As the commission stated above, the true-up provision of the rule provides for a method of collecting or refunding any differences between actual PCRF revenues collected and the revenues that the PCRF was set to collect. The purposes of the reconciliation proceeding, however, are to examine the reasonableness, necessity, and prudence of the expenses included for recovery in the PCRF; to determine any disallowances or other appropriate adjustments that may be reasonable; and to ensure that the revenues recovered under the PCRF appropriately match the reasonable, necessary, and prudent PCRF expenses.

ETI's Proposed Pre-approval of Capacity Contracts

ETI stated that it is critical that the rule provide a mechanism for the utility to seek prior approval of both third-party purchased power contracts and affiliate contracts in appropriate circumstances. ETI stated that the regulatory risk is real, and much like the situation with qualifying facilities contracts, the utility, and merchant generators and financers, need assurance of cost recovery in order to initiate long-term purchased power contracts and to embark upon large, capital-intensive projects like new generation plants.

ETI asserted that the rule should allow for contemporaneous approval of purchased power contracts by the commission, whether affiliate or otherwise. ETI argued that purchased power capacity costs are a pass-through; the utility receives no benefit or profit from collecting purchased power capacity costs from its customers and then paying them to the seller of the power. Therefore, ETI asserted, there is no purpose in setting up a regulatory process that incorporates regulatory lag and creates unnecessary risk concerning whether the utility can recover all of its costs. ETI argued that, with risk comes cost, so to the extent there is regulatory lag, that risk will be implicitly accounted for in the borrowing and equity costs of the utility or in the price of power that the seller requests when selling to the utility, which is then passed on to the customer. ETI argued that the seller would also face a risk to the extent the contract included a “regulatory out” clause that would allow the utility to terminate the transaction if the utility were precluded from timely recovering its purchased power capacity costs. ETI stated that the customer would benefit from a process that minimizes regulatory risk that the utility would face when entering purchased power arrangements.

ETI also argued that providing for an approval process at the time a contract is entered would help foster competition in the wholesale market by facilitating an independent power producer’s ability to finance a project. ETI stated that the scope of the review will be the same as a review in a fuel reconciliation proceeding because all of the information that should be used for evaluating the purchased power contract will be available at the time it is entered.

ETI asserted that it is within the commission’s authority to provide a process for approval of a contract before costs are incurred under the contract, referencing §25.238(a)(3) , subject to repeal in this project, which provides for a commission pre-approval of a purchased power contract. ETI argued that, rather than repealing the pre-approval provision in §25.238(a)(3) , the proposed rule could be amended to provide for a review of purchased power contracts by borrowing from this existing provision. ETI also provided language to allow for commission approval of purchased power contracts, which it asserted was worded to avoid arguments that the commission has restricted itself from entertaining requests for approval of contracts outside of the context of this rule.

EPE and SWEPCO supported ETI's proposal. EPE stated that this provision, which is similar to the current provision that allows distribution utilities to seek approval of PPAs and the provision that previously existed in the commission's fuel rule that allowed approval of long-term fuel contracts, would facilitate the timely regulatory review of new purchased power contracts. EPE and SWEPCO stated that including the new subsection would reduce the regulatory risk of disallowances associated with the reviewing of such contracts some time after an agreement had been entered into by the utility.

SWEPCO added that ETI's proposed revision could also provide a mechanism for including affiliate purchases in the PCRF formula.

Parties that are not electric utilities generally opposed ETI's proposal. TIEC stated that ETI insinuates that the current PCRF rule allows this type of review, but ignores the fact that the pre-approval process in the existing PCRF rule is explicitly limited to "distribution utilities," a term that does not include bundled utilities that own generation. TIEC argued that, for bundled utilities, the prudence and reasonableness of a PPA cannot be effectively reviewed in isolation. Cities and TIEC argued that, to pre-approve a PPA, the commission would need to examine whether the contract was necessary in the context of the utility's overall generation needs and existing resources, and whether the most cost-effective option was selected. TIEC stated that the type of pre-approval process ETI proposes would also further disperse utility rate review into numerous unnecessary and inefficient proceedings, making it more difficult for customer groups to effectively participate and increasing the administrative burden on the commission. TIEC asserted that the review should remain in base-rate proceedings where all the necessary information is readily available.

TIEC argued that there is nothing requiring ETI to include a “regulatory out” clause in its contracts, and if this term makes it difficult to obtain financing then ETI can decide not to include it. TIEC stated that ETI is statutorily required to make the best resource decisions on behalf of its customers. TIEC stated that ETI’s arguments are not a legitimate reason to break down the existing ratemaking process into unmanageable and unnecessary piecemeal proceedings at customers’ and the commission’s expense. TIEC asserted that because ETI’s proposal for contract pre-approval was not part of the published rule, TIEC believes that it is outside of the scope of this rulemaking and would likely require a new rule to be published with a new opportunity for comments.

State Agencies said it does not agree with ETI that the PCRF process is the proper forum for adjudicating the reasonableness of an affected contract, and that it is more appropriate that this be done at a reconciliation proceeding, just as the prudence of fuel costs is reviewed in a fuel reconciliation proceeding.

Cities recommended rejecting ETI’s proposal that the commission issue an advisory opinion on the reasonableness of a utility’s capacity contracts and then preclude any further review of the utility’s cost incurred under such a contract. Cities stated that precluding further review of the contracts could potentially permit a utility to maintain capacity costs that have become inefficient and non-cost effective.

Commission response

The commission appreciates the comments of the parties, and agrees with ETI, EPE, and SWEPCO that allowing for pre-approval of arrangements for the purchase of capacity for later recovery of associated capacity costs through the PCRF is appropriate. The commission further determines that such pre-approval should be required before allowing utilities to seek the inclusion of any affiliate-related purchased capacity costs in the PCRF, but should be optional for capacity purchases from unaffiliated entities. Such pre-approval will provide for reduced regulatory risk and thus may lower the cost of financing for generation plants. By creating a pre-approval process outside of the annual PCRF filing, the heightened standard required for the review of affiliate transactions can also be met without interfering with the streamlined nature of the annual filings. In addition, the adopted rule limits the number of times a utility can apply for such pre-approval, both within a year and between rate cases, which will conserve commission and intervenor resources and address TIEC's concern that the pre-approval proceedings will be overly burdensome to parties and ratepayers. Subsections (c)(3), (d), and (h)(1) of the rule have been modified accordingly.

Issues Specific to Sharyland

Sharyland stated it has a PCRF in its tariff for its Stanton, Colorado City, Brady, and Celeste divisions adopted under the current rule, and that until Sharyland institutes retail competition under the commission's Order, the power cost recovery factor in its tariff will remain in effect. Sharyland stated that, if the rule were adopted, it does not plan to seek approval of a new PCRF under the rule but to continue to utilize its existing PCRF until it transitions to retail competition in 2014. Sharyland requested that the proposed rule be modified to address its situation, suggesting that the rule make clear that any utility currently utilizing a PCRF under the current rule is authorized to continue utilizing that factor until it is terminated. Sharyland also requested a provision that addresses the termination of a PCRF established under the current rule for a utility that transitions to retail competition. Sharyland stated that, after retail delivery tariffs are implemented and it terminates its current PCRF, a rider will be necessary to allow Sharyland to credit or charge any remaining over-recovery or under-recovery amounts under the PCRF to its customers, as appropriate. Sharyland provided proposed language consistent with its comments.

Cities, ETI, and OPUC did not object to Sharyland's continued use of the current PCRF rule. OPUC stated it takes no position with respect to the particular rule language proposed by Sharyland. TIEC stated that it did not oppose the concept behind Sharyland's proposed language, but that the language may need to be further refined and limited to prevent unintended applications.

Commission response

The commission appreciates the comments of Sharyland and the parties. The commission agrees with Sharyland that language allowing the grandfathering of currently existing PCRFs is appropriate, and has added subsection (k) to the rule accordingly.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission has made changes consistent with the discussion above and to clarify its intent.

The repeal of §25.238 and new §25.238 are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 2007 and Supp. 2012) (PURA) which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §36.051, which states that in establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses; PURA §36.058, which limits the commission's authority to allow the recovery of a payment made by an electric utility to an affiliate; PURA §36.204, which grants the commission the authority to allow timely recovery of the reasonable costs of purchased power; PURA §36.205, which permits the commission to use any appropriate method to provide for the adjustment of the cost of purchased electricity that has been accepted by a federal regulatory authority or approved after a hearing by the commission; and PURA §36.206, which provides what may be included in a purchased power cost recovery factor.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 36.051, 36.058; 36.204, 36.205, and 36.206.

§25.238. Power Cost Recovery Factors (PCRF). (REPEAL)

§25.238. Purchased Power Capacity Cost Recovery Factor (PCRF).

(a) **Application.** This section applies to an electric utility that sells electricity.

(b) **Definitions.** The following terms, when used in this section, have the following meanings unless the context indicates otherwise.

(1) **Class billing determinants** -- Kilowatt-hours (kWh) for each class that is not billed using a demand charge, and kilowatts (kW) for each class that is billed using a demand charge.

(2) **Cost year** -- the most recent historical 12-month period for which data are available at the time a utility prepares an application to establish, adjust, or terminate a PCRF.

(3) **Net production capacity invested capital --** Production capacity invested capital costs recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 310 - 317, 320 - 326, 330 - 337, and 340 - 347, less accumulated depreciation and adjusted for any changes in production capacity-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48.

(c) **Establishment, adjustment, and termination of a PCRF.**

(1) A utility may apply for establishment of a PCRF rider only if all of the following conditions are met:

(A) the utility's most recent comprehensive base-rate proceeding established sufficient information to allow for the determination of values for the parameters in subsection (h) of this section;

(B) no more than two years have passed since the final order in the utility's most recent comprehensive base-rate proceeding;

(C) the utility has not had a PCRF in effect within the last year; and

(D) no PCRF has been in effect for the utility since the final order in the utility's most recent comprehensive base-rate proceeding.

(2) The application in which the utility applies for the establishment, adjustment, or termination of a PCRF rider shall be limited to issues related to the establishment, adjustment, or termination of the PCRF rider.

(3) The PCRF shall not include:

(A) the cost of capacity purchased directly or indirectly from an affiliate, as defined in §25.5(3) of this title (relating to Definitions), of the utility, including, without limitation, whether such capacity is acquired through one or more intermediaries or pursuant to a FERC approved agreement or tariff of a Regional Transmission Organization or Independent System Operator, unless such affiliate-related purchases have been previously approved by the commission in a proceeding under subsection (d) of this section;

(B) the cost of capacity owned by the utility;

(C) any costs recoverable by the utility under §25.236 of this title (relating to Recovery of Fuel Costs), including purchases of firm energy;

(D) any costs for purchases made through day-ahead or real-time markets of a Regional Transmission Organization or Independent System Operator.

(4) Upon the establishment of a utility's PCRF, the utility shall annually file an application for an adjustment of the PCRF. The cost year used in an annual PCRF adjustment shall be the 12-month period that immediately follows the cost year used to set the existing PCRF. In addition, the utility shall file the application to adjust the PCRF promptly after the relevant cost-year data become available. The commission may establish a schedule for the filing of such applications.

(5) A utility may terminate its PCRF as part of any annual PCRF adjustment proceeding. The final order including the termination of a PCRF shall specify the date by which the utility shall be required to file an application for the final reconciliation of the costs and revenues associated with the terminated PCRF.

(6) Commission staff may petition at any time to terminate a utility's PCRF.

(7) A utility's request to establish, adjust, terminate, or reconcile a PCRF shall include the utility's direct testimony supporting the request.

(d) **Pre-approval of purchased power agreements.**

(1) The commission may pre-approve a utility's executed agreement for the purchase of power capacity from an affiliate if it finds that the agreement is reasonable, and the utility may thereafter seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(2) Though not required for inclusion in a PCRF rider, a utility may seek commission review of the reasonableness of a utility's executed agreement for the purchase of

power capacity from a non-affiliate, and the utility may seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(3) Agreements under paragraphs (1) and (2) of this subsection may include an agreement for the purchase of capacity to be delivered in the future that relies on the construction of a generating unit or units.

(4) An application in which the utility applies for pre-approval of purchased power capacity agreements under this subsection shall be limited to issues related to the pre-approval of such agreements.

(5) A utility may apply for pre-approval of purchased power agreements under this subsection no more than once per year, and no more than three times between comprehensive base-rate proceedings.

(e) **Notice of PCRF proceeding.**

(1) Within one commission working day of filing an application limited to establishing, adjusting, or terminating a PCRF, a utility shall provide notice of the application in accordance with the following:

(A) **Method of notice.**

(i) The utility shall serve notice of the application on the parties to the utility's last PCRF reconciliation proceeding or, if there has been no PCRF reconciliation proceeding, on the parties to the utility's last comprehensive base-rate proceeding.

(ii) The utility shall issue a news release and post the news release on its website.

(B) **Content of notice.** Notice provided pursuant to paragraph (1) of this subsection shall include the following:

(i) The date the application was filed;

(ii) A description of the application, including the relief requested;

(iii) The date of the intervention and hearing request deadline. The date of the intervention and hearing request deadline shall be 30 days after the application was filed, except that if the date would fall on a day that is not a commission working day, the intervention and hearing request deadline shall be the first commission working day after the 30^{th} day after the application was filed;

(iv) To the extent applicable, the existing PCRF and the proposed PCRF by rate class, and the percentage difference between the two;

(v) For an application seeking to establish or adjust a PCRF, the following statement: "The PCRF is subject to final review in the next PCRF reconciliation.";

(vi) The statement, "Persons with questions or who want more information on this application may contact (utility name) at (utility address) or call (utility toll-free telephone number) during normal business hours. A complete copy of this application is available for inspection at the address listed above"; and

(vii) The statement, "Persons who wish to intervene in the proceeding for this application, or who wish to provide their comments concerning this application, should contact the Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326, or call (512) 936-7120 or toll-free at (888) 782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may call (512) 936-7136 or use Relay Texas (toll-free) 1-800-735-2989."

(C) **Proof of notice.** Within five commission working days from the filing of the application limited to establishing or adjusting a PCRF, the utility shall file proof in the form of an affidavit that it complied with this paragraph.

(2) If a utility applies to reconcile a PCRF in a base-rate proceeding, the appropriate method and proof of notice set forth in §22.51 of this title (relating to Notice for Public Utility Regulatory Act, Chapter 36, Subchapters C-E; Chapter 51, §51.009; and Chapter 53, Subchapters C-E Proceedings) shall apply. The notice shall include a description of the requested change to the PCRF.

(3) If a utility applies to reconcile a PCRF outside of a base-rate proceeding, the method of notice set forth in §25.235(b)(1)(B) of this title (relating to Fuel Costs-General) shall apply. The proof of notice set forth in §25.235(b)(3) of this title shall apply. The notice shall include a description of the requested reconciliation of the PCRF.

(f) **Procedural schedule.** Upon the filing of an application limited to the annual adjustment of a PCRF pursuant to this section, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding as follows, except where good cause supports a different procedural schedule:

(1) within 60 days after a sufficient application was filed, if no hearing is requested within 30 days of the filing of the application; or

(2) within 120 days after a sufficient application was filed, if a hearing is requested within 30 days of the filing of the application. If a hearing is requested, the hearing will be held no earlier than the first working day after the 45th day after a sufficient application was filed.

(g) **Exclusion from fuel factor.** Costs that are recovered through a PCRF shall be excluded in calculating the utility's fixed fuel factor as defined in §25.237 of this title (relating to Fuel Factors).

(h) **PCRF formula.**

(1) The PCRF for each rate class shall be calculated using the following formula:

$$\mathbf{PCRF = (\{(((PPC_{CY} + AAC_{CY} + APC_{M}) * TRAF_{CY}) - OSM_{CY}) * CAF_{CY}\} - \{(PPC_{RC\text{-}CLASS} + APC_{RC\text{-}CLASS} - OSM_{RC\text{-}CLASS}) * LGR\} - \{((PCIC_{RC\text{-}CLASS} * ROR_{AT}) + PCDEP_{RC\text{-}CLASS} + PCFIT_{RC\text{-}CLASS} + PCOT_{RC\text{-}CLASS}) * LGI\} + CTU) / CBD_{E}}$$

Where:

PPC_{CY} = Cost-year purchased power capacity costs from entities that are not affiliates, in accordance with subsection (c)(3) of this section.

AAC_{CY} = Cost-year purchased power capacity costs from entities that are affiliates and which costs are incurred from agreements that have been pre-approved by the commission in a proceeding under subsection (d) of this section as of the date of the filing of the instant PCRF application.

APC_{M} = The lesser of:

- purchased power capacity costs from affiliates used to set base rates in the utility's last comprehensive base-rate proceeding, or
- cost-year purchased power capacity costs from affiliates less AAC_{CY}.

OSM_{CY} = Cost-year margins from wholesale power capacity sales transactions.

$TRAF_{CY}$ = Cost-year value of the Texas retail jurisdiction production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.

CAF_{CY} = Cost-year value of the corresponding rate class production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.

$PPC_{RC\text{-}CLASS}$ = Purchased power capacity costs from entities that are not affiliates, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$APC_{RC\text{-}CLASS}$ = Purchased power capacity costs from affiliates allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$OSM_{RC\text{-}CLASS}$ = Margins from wholesale power capacity sales allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

LGR = The greater of (CBD_{CY} / CBD_{RC}) or 1.

CBD_{CY} = Cost-year rate class billing determinants.

CBD_{RC} = Rate class billing determinants used to calculate base rates from the utility's last comprehensive base-rate proceeding.

$PCIC_{RC\text{-}CLASS}$ = Net production capacity invested capital allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

ROR_{AT} = The after-tax rate of return used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCDEP_{RC\text{-}CLASS}$ = Depreciation expense, as related to gross production capacity, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCFIT_{RC\text{-}CLASS}$ = Federal income tax, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCOT_{RC\text{-}CLASS}$ = Other taxes, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding, and not including municipal franchise fees.

LGI = The greater of $((CBD_{CY} – CBD_{RC}) / CBD_{RC})$ or 0.

CTU = The rate class under/(over)-recovery, including interest, as calculated in subsection (i) of this section.

CBD_E = Estimated PCRF rate year class billing determinants.

(2) Where the cost year used in setting a PCRF includes a change in base rates due to a comprehensive base-rate proceeding, parameters in the PCRF formula that refer to values from the utility's last comprehensive base-rate proceeding shall be calculated by prorating the values from the relevant base rate-proceedings across the cost-year.

(i) **True-up.** After establishment of an initial PCRF, a subsequent PCRF cost year is expected to contain portions of two different PCRF rate years. Therefore, for purposes of calculating class over- or under-recoveries for use in a proceeding to adjust the PCRF, previous PCRF revenue requirements from PCRF rate years in effect during the cost year shall be prorated across the cost year. For each rate class, the difference between the prorated cost-year PCRF revenue requirement that previous PCRFs were set to recover from that class and the actual cost-year PCRF revenues recovered from that class, with interest on the balance calculated at the rate established annually by the commission pursuant to §25.28(c) and (d) of this title (relating to Bill Payment and Adjustments), shall be credited or charged to that class when calculating the adjusted PCRF. In the event that a PCRF rider is terminated, any over- or under-recovery amounts, with interest applied, shall be included in a separate rider.

(j) **Reconciliation of PCRF expenses.**

(1) The reasonableness and necessity of expenses recovered through the PCRF shall be reviewed, and such costs and corresponding PCRF revenues shall be reconciled, as part of any proceeding initiated under §25.236(b) of this title. Upon motion and showing of good cause, a PCRF reconciliation proceeding may be severed from or consolidated with other proceedings.

(2) In a proceeding in which PCRF costs are being reconciled, the electric utility has the burden of showing that:

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

(B) it has properly accounted for the amount of purchased power capacity-related revenues collected pursuant to the PCRF and corresponding to costs reviewed during the reconciliation period.

(3) Any refunds or surcharges resulting from a PCRF reconciliation, with interest applied, shall, in the annual PCRF proceeding immediately subsequent to the filing of the final order in the reconciliation proceeding, be incorporated into the true-up balances described in subsection (i) of this section. In the event that no PCRF rider is in effect subsequent to a PCRF reconciliation, such refunds or surcharges, with interest applied, shall be included in a separate rider.

(k) **Transition Issues.**

For a utility subject to a commission order to transition to retail competition as of the effective date of this section, the utility's existing power cost recovery factor in its tariff approved under the prior rule shall continue to be effective until the effective date of new unbundled retail delivery tariffs for the utility, at which time the power cost recovery factor shall be terminated. Any over- or under-recovery amounts, with interest applied, shall be included in a separate rider to the utility's retail delivery tariffs to be established in the proceeding that approves such tariffs and shall be credited or charged to customers as appropriate. The utility shall file monthly reports with the commission showing all such amounts until no remaining amounts remain to be credited or charged, at which time the utility shall file a final report with the commission.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be within the agency's legal authority to adopt. It is therefore ordered by the Public Utility Commission of Texas that the repeal of §25.238, relating to Power Cost Recovery Factors and new §25.238, relating to Purchased Power Cost Recovery Factor are hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS on the 23rd day of MAY 2013.

PUBLIC UTILITY COMMISSION OF TEXAS

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DONNA L. NELSON, CHAIRMAN

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KENNETH W. ANDERSON, JR., COMMISSIONER

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