PROJECT NO. 45124

RULEMAKING REGARDING DC TIES PURSUANT TO SB 933, MUNICIPALLY OWNED UTILITIES PURSUANT TO SB 776, AND NON-ERCOT UTILITIES PURSUANT TO HB 1535 OF THE 84TH LEGISLATURE (R.S.); AND COMPETITIVE RENEWABLE ENERGY ZONES	**§ § § § § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §§25.101, 25.174, AND 25.192 AS APPROVED AT THE JUNE 9, 2016 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to 16 TAC §25.101, relating to Certification Criteria, §25.174, relating to Competitive Renewable Energy Zones, and §25.192, relating to Transmission Service Rates with changes to the proposed text as published in the February 26, 2016 issue of the *Texas Register* (41 TexReg 1213). The adopted amendments will implement Senate Bill 776, Senate Bill 933, and House Bill 1535 of the 84th Legislature (R.S.), as well as make modifications to the Competitive Renewable Energy Zones (CREZs) rule. These amendments are adopted under Project Number 45124.

The commission received comments on the proposed amendments from Apex Clean Energy Management, LLC (Apex), CPS Energy, EDF Renewable Energy, Inc., the Electric Reliability Council of Texas (ERCOT), Entergy Texas, Inc. (ETI), the Environmental Defense Fund (EDF), Golden Spread Electric Cooperative, Inc. (Golden Spread), the Lone Star Chapter of the Sierra Club (Sierra Club), Luminant Generation Company, LLC and Luminant Energy Company, LLC (collectively, Luminant), the Office of Public Utility Counsel (OPUC), the Solar Energy Industries Association (SEIA) jointly with the Texas Solar Power Association (TSPA), the Texas

Competitive Power Advocates (TCPA), the Texas Industrial Energy Consumers (TIEC), and the Wind Coalition.

Reply comments were received from the Brownsville Public Utilities Board (BPUB), EDF Renewable Energy, ERCOT, Luminant, and TIEC, as well as AEP Texas Central Company, AEP Texas North Company, CenterPoint Energy Houston Electric, LLC, Cross Texas Transmission, LLC, Electric Transmission Texas, LLC, Lone Star Transmission, LLC, Oncor Electric Delivery Company LLC, Sharyland Utilities, L.P., and Texas-New Mexico Power Company jointly (collectively, ERCOT Utilities) and the City of Garland (Garland), Denton Municipal Electric (DME), and Texas Municipal Power Agency (TMPA) jointly.

<u>§25.101 – Certification Criteria</u>

<u>§25.101 – General Comments</u>

ETI proposed improving the efficiency of the transmission line certificate of convenience and necessity (CCN) review process by extending the provision giving weight to ERCOT conclusions regarding need in CCN cases to also give weight to similar findings by other regional transmission operators (RTOs). ETI also proposed adding an option to expedite CCN proceedings for certain customer-driven projects.

In reply comments, TIEC responded that recommendations regarding determinations on need for transmission facilities by RTOs under the jurisdiction of the Federal Energy Regulatory Commission (FERC) should not be given "great weight" because the commission does not have jurisdiction over these RTOs and therefore cannot control their planning policies as it can for

ERCOT. Therefore, TIEC argued that granting the same level of deference to such RTOs is not appropriate. However, TIEC agreed with ETI that expedited proceedings for facilities to interconnect a new retail customer or merchant generators (i.e. customer-driven projects) could be appropriate under certain circumstances.

Commission Response

The purpose of the commission's amendments to this rule is to conform the rule to statutory changes. ETI's proposed changes do not pertain to the statutory changes, and therefore, the commission declines to make the changes proposed by ETI. Furthermore, the commission would require additional information and evaluation of the proposed changes in order to reach a decision on their substantive merits.

<u>§25.101(a)(7) and (b)(4) – Tie Lines</u>

Golden Spread offered a modification to the proposed amendment aimed at maintaining the operational independence of ERCOT from FERC-jurisdictional regions by limiting the definition of a tie line to specifically direct current (DC). Golden Spread also recommended that merchant tie lines, which it asserted are capable of importing and exporting power from ERCOT, be subject to ongoing commission oversight similar to that of power generating companies that import power from outside the state to ERCOT. TIEC acknowledged the complicated nature of the DC tie issue, and recognized the potential for reliability concerns and impacts on market prices. In reply comments, TIEC disagreed with the suggestion by Golden Spread to modify the definition of a tie line, arguing that no changes to the definition of a tie line are necessary or appropriate because the language that the commission has proposed exactly tracks the language of Public Utility Regulatory Act (PURA) §37.051(c-1).

TCPA, Luminant, and ERCOT all proposed amendments to §25.101(b)(4). TCPA and Luminant stated that the physical flows associated with exporting wind may require a careful assessment of generation deliverability for all resources under a spectrum of system conditions, and that additional analyses will likely be needed to properly understand the impact of the proposed DC ties on ERCOT system reliability, economics, and priority dispatching. Luminant asserted that managing transmission congestion in connection with approval of a large tie line is critical and to address such issues proposed the use of Constraint Management Plans (CMPs), as set forth in ERCOT Nodal Operating Guide Section 11. ERCOT stated that it supports the proposed amendments to subsections (b)(3)(A) as well as (b)(4), but requested that the commission further revise subsection (b)(4) to provide additional details on the studies that ERCOT will be required to submit with DC tie CCN applications. ERCOT also made a distinction between the proposed criteria for DC ties and the existing economic and reliability criteria for transmission lines.

TIEC disagreed in its reply comments that a CMP is necessary or appropriate to prevent imports from displacing certain generators, as Luminant and TCPA proposed. ERCOT shared Luminant's concern that integrating DC ties with the security-constrained economic dispatch (SCED) would present a host of implementation challenges that would need to be addressed. However, in its reply comments, ERCOT stated that it would be worthwhile to first conduct an assessment of the costs and benefits of a SCED solution prior to considering other alternatives such as a CMP.

In reply comments, ERCOT reiterated that SB 933 appears to require a finding of need without regard to whether the proposed tie line would be privately or publicly funded, and therefore ERCOT's comments were more narrowly focused on the nature of such a need determination. ERCOT acknowledged that some of the comments implied an understanding that a tie line CCN applicant should be required to first obtain an ERCOT study with an analysis similar to the type of study conducted for the interconnection of new generation, rather than a study of need. ERCOT noted that such a study would be appropriate only if the statutory CCN requirement is understood not to apply to all new tie lines, with the exception of the proposed Southern Cross project which is exempted from the need requirement. However, if the statute does require new tie line developers to first obtain a CCN, as ERCOT assumes, then the analysis of the reliability implications should already be addressed as part of ERCOT's need assessment. ERCOT stated that it would not oppose any clarification that an ERCOT-approved reliability assessment should be required, if desired by the commission. ERCOT also stated that PURA §37.051(c-2) gives the commission authority to impose "reasonable conditions" on the interconnection of the Southern Cross project as part of any CCN proceeding. ERCOT offered a number of issues that should be addressed before the Southern Cross project is permitted to interconnect to the ERCOT system. However, ERCOT stated that it did not understand the statute to require that any or all of these issues must be addressed as part of the Garland CCN proceeding or in this rulemaking if the commission's primary purpose in this proceeding is to establish the general requirements for tie line projects that are subject to the need determination described in PURA §37.051(c-1).

Both Luminant and ERCOT asserted that Golden Spread's proposed changes to the definition of a tie line are unnecessary, but stated that they would have no concern with Golden Spread's alternative request seeking to clarify that the term “tie line” does not include grid-switchable generation. Additionally, ERCOT disagreed in its reply comments with Golden Spread’s proposed substitution of the phrase “transfer power into or out of” in place of the proposed phrase “enable traditional power to be imported into or exported out of” ERCOT. ERCOT also recommended against explicitly restricting tie line requirements to direct current ties because DC ties are not the only devices capable of moving power between asynchronous regions. Luminant provided several examples of such non-DC asynchronous interconnections in its reply comments to Golden Spread.

In Luminant’s reply comments, it agreed with Golden Spread that merchant owners and operators of tie facilities should be subject to ongoing oversight by the commission and suggested that the commission should open a separate rulemaking project to consider what requirements would be appropriate.

Commission Response

In response to ERCOT’s request, the commission has clarified the amendment to subsection (b)(4) to state that the study of the tie line by the ERCOT independent system operator shall, at a minimum, include an ERCOT-approved reliability assessment. The commission has not made other changes in response to these comments regarding tie lines. The amendments appropriately track the language of PURA §37.051(c-1).

<u>§25.101(a)-(c) – Certificates of Convenience and Necessity for an Municipally-Owned Electric Utility (MOU) or Municipal Power Agency (MPA)</u>

Golden Spread offered comments arguing that the difference between municipal borders and service territory boundaries as it relates to the reporting requirements (§25.83) of new electric transmission lines is significant, pointing out that municipal boundaries change with regularity and are not relevant to a utility's service territory. Golden Spread therefore recommended that the commission revise the language to rely on service territories in lieu of municipal boundaries.

CPS Energy stated that affected MOUs and commission staff should work together during the CCN application process in order to avoid the duplication of efforts or conflicts between commission requirements and the MOUs' city governing bodies. CPS Energy also included an exhibit demonstrating its current siting and routing process.

BPUB's reply comments to Golden Spread asserted that the proposed amendments regarding the reporting requirements of new transmission lines outside municipal boundaries are unambiguously consistent with PURA §37.051(g), and that BPUB supports the commission's orderly monitoring of new transmission construction. Garland, DME, and TMPA replied in joint comments that Golden Spread's proposed revisions to subsection (b)(3) should be rejected, because they are contrary to the plain language of the statutory provisions enacted by the Legislature in SB 776.

Commission Response

The commission recognizes that there may be potential benefits in avoiding or mitigating duplicative or conflicting processes as raised in the comments of CPS Energy. However, those issues are not necessary to implement the statutory changes in this proceeding and therefore the commission has not made changes to the proposed amendments in response to

these comments. The amendments to subsection (b)(3) appropriately track the language of PURA §37.051(g) and require that MOUs/MPAs adhere to the reporting requirements of §25.83 for certain types of new electric transmission lines, and therefore the commission has not made any changes in response to the comments of Golden Spread.

<u>§25.174 – Competitive Renewable Energy Zones</u>

<u>§25.174 - General Comments</u>

Several parties commented generally on aspects of proposed amendments to §25.174 relating to the commission's authority to designate new CREZs. Apex argued that the commission can refrain from implementing additional CREZ projects after 2007, but that it does not have the ability to repeal its legislatively bestowed CREZ authority. Apex argued that the power to repeal the commission's CREZ authority lies with the Legislature; the commission cannot repudiate statutory duties or accompanying powers delegated to implement those duties, and furthermore an agency rule must be consistent with the statute to be valid. Similarly, Sierra Club asserted that the commission lacks authority to declare through rulemakings that it cannot authorize further transmission projects. Sierra Club further averred that if the commission were to administratively declare that no CREZ can be designated in the future, it would be assuming a legislative function in contradiction of Texas law. Sierra Club, SEIC, EDF, and Apex all asserted that the commission lacks the authority to declare that it cannot authorize further transmission projects under PURA §39.904(g) by changing §25.174 in a rulemaking. Similarly, the Wind Coalition argued that the proposed amendments effectively repeal PURA §39.904.

In addition, several parties commented on SB 931 of the 84th Legislative Session, which proposed to repeal PURA §39.904. EDF Renewable Energy noted that the commission proposed changes to PURA §39.904(h) in its 2015 *Scope of Competition in Electric Markets* Report, but that the Legislature chose not to enact such changes. Sierra Club asserted that the Legislature chose not to act on SB 931, and therefore any attempt by the commission to declare that no future CREZ could be authorized is inappropriate.

Several parties discussed the benefits of retaining the commission's authority to designate future CREZs. Sierra Club argued that future CREZ areas could be beneficial, perhaps supporting the U.S. Environmental Protection Agency's Clean Power Plan regulations and accommodating the expected solar generation growth contemplated in ERCOT's Long Term System Assessment. Apex cited the potential benefits of future CREZ with respect to the large amount of untapped wind capacity, current operational issues with Panhandle wind projects, pending federal emissions regulations, large-scale development of solar in west Texas, shifting energy use, and the increasing pace of coal generation retirements alongside falling natural gas prices. EDF also argued that, in the absence of a repeal of PURA §39.904 by the Legislature, the commission should not amend the rule to conflict with continuing statutory requirements, especially when previous CREZ actions have provided significant benefits.

In reply comments, TIEC argued that CREZ was a one-time mandate, and that the commission has full authority to sunset the CREZ designation process by rule to thus require all future projects to existing CREZs to show need. TIEC argued that some commenters inaccurately contended that the commission lacks the authority to sunset the CREZ process by rule. TIEC further argued that

PURA §39.904(g) only requires the commission to initially designate CREZ and develop a single plan to develop transmission capacity. TIEC asserted that this provision does not represent a continuing mandate to designate additional CREZs. EDF Renewable Energy responded that TIEC's argument constitutes too narrow a reading of the statute, and that the statute does not require that all CREZs be designated at the same time, nor is the commission's authority to develop a plan bounded in time.

EDF Renewable Energy asserted that, in the Order on Rehearing adopting the 2008 CREZ Order, potential expansion was identified as a benefit of the CREZ plan and further that the commission in Project No. 34560 anticipated that the CREZ process may also be used for areas outside of ERCOT. EDF Renewable Energy argued that the commission should not adopt TIEC's retroactive declaration, and should decline TIEC's alternative recommendation, which, like the proposed amendments, would remove the commission's discretion to require a need finding for a CREZ project. EDF Renewable Energy argued that the commission should instead preserve the option to apply the need exception only in the event any future CREZ transmission projects are approved.

<u>§25.174(a)</u>

Sierra Club stated that it was supportive of language in §25.174(a), which it stated was clear that the second circuit on the Panhandle is a continuation of CREZ and that the original CREZ projects from 2007 are now completed. Similarly, Apex argued that it may be appropriate to recognize that the first phase of the CREZ implementation is complete, but Apex further asserted the value in maintaining the policy for potential future use, even in modified form. In reply comments, EDF Renewable Energy also argued that it was important to codify the commission's determination that the second circuit to the Sharyland line in the Panhandle is the last CREZ project under the CREZ plan approved in 2008.

SEIA, TSPA, and EDF argued that the proposed amendments to §25.174(a) would limit the commission's ability to establish a CREZ to those projects arising from the proceedings initiated in 2007. These commenters asserted that this would ignore the commission's continuing obligations pursuant to PURA §39.904(g) and would significantly limit the commission's authority in a time of continuing technological and cost changes in renewable energy.

§25.174(b)

Apex and Sierra Club stated that they opposed the proposed amendments that strike the phrase "and in subsequent years as deemed necessary by the commission" in subsection (b), arguing that this would end any future CREZ by removing the commission's CREZ authority altogether. Sierra Club argued that this change, together with the proposed language in §25.101(b)(3)(A)(i) eliminating the current exception to a requirement for an economic cost-benefit study for CREZ transmission, would eliminate a valuable policy tool and force all future CREZ projects to pass a narrow economic test.

TIEC argued that in order to implement the commission's intent to sunset the exemption from the need criteria for transmission projects intended to serve a CREZ, subsection (b) should be amended to affirmatively ensure that all future transmission projects will require a need finding. To accomplish this, TIEC recommended striking the entirety of the language that the "commission shall consider" CREZs, and instead add proposed language to establish that the designation of CREZs shall be completed by January 1, 2009.

TCPA asserted that CREZ is a complete project, and that all future transmission should be evaluated through the standard planning process, after passing all economic or reliability evaluations. TCPA asserted that the proposed amendment in subsection (b) that removes the language referencing years subsequent to 2007 is appropriate and adequately addresses the concerns and direction expressed by the commission.

§25.174(e)(2)

Several commenters offered alternate language which attempts to better clarify the phrase, "…transmission project intended to serve CREZ" rather than striking that language completely. The Wind Coalition argued that the commission should amend the rule to make clear that this phrase has a limited and specific meaning: only those projects intended by the commission to serve a CREZ, which would be indicated in an order approving a transmission plan under PURA §39.904(g)(2). The Wind Coalition argued that this would eliminate the concern that any project in a CREZ area or any project intended by a CCN applicant could be considered a project "to serve a CREZ."

SEIA and TSPA argued that the proposed amendments conflict with statutory requirements. SEIA and TSPA asserted that PURA §39.904(h) exempts a transmission line proposed to serve a CREZ from the requirements of PURA §37.056(c)(1) and (2), which require the commission to review the adequacy of existing transmission service and the need for additional transmission service before granting a CCN. SEIA and TSPA stated that, despite language that they believe is clear in the statute, the commission's proposed repeal of the exemption of a proposed CREZ transmission line from the requirements of §25.101(b)(3)(A) and the proposed amendments in §25.174(e)(2) would require a transmission line proposed to serve a CREZ to comply with requirements of PURA §37.056(c)(1) and (2). Similarly, EDF argued that the proposed amendments would require a future applicant for a CREZ transmission line to meet the need criteria from which it should be exempt under PURA §39.904(h). EDF further asserted that the proposed amendments in §25.174(e)(2) are also inconsistent with the exemption provided by PURA §39.904(h). The Wind Coalition argued that the proposed language would erase all distinction between CREZ and non-CREZ projects in PURA §39.904(h) and that it would repeal the commission's authority to consider any future CREZ.

EDF Renewable Energy stated that it interprets the commission's objective to be that, after the Panhandle second circuit, all future CCN applications for transmission lines in a CREZ must address the need criteria in PURA §37.056(c)(1) and (2). To effectuate this, EDF Renewable Energy proposed alternative language in §25.174(e)(2) that a transmission project is intended to serve a CREZ only if it is part of a plan approved by the commission to develop transmission capacity. In its reply comments, EDF Renewable Energy noted that EDF, SEIA, and TSPA recommended that the commission take no action and simply reject the proposed amendments, seeing no need to repeal or significantly limit the current rules regarding CREZ. EDF Renewable Energy asserted that a "no action" approach is not unreasonable, but it also maintained that it is appropriate to amend §25.174(e)(2) to end any possible arguments that broadly worded language in PURA §39.904(h) confers an ongoing right to build CREZ without showing need under PURA §37.056(c)(1) and (2).

Apex argued that the proposed amendments in subsections (a) and (e)(2) are sufficient to achieve the commission's goal of affirming the completion of the projects arising from the 2008 CREZ Order. Apex asserted that going beyond this to remove the commission's CREZ authority would be an overreach of the commission's administrative authority and that such action conflicts with PURA.

SEIA, TSPA, and EDF recommended rejecting the proposed amendments to §25.101 and §25.174 that relate to the CREZ and the development of transmission projects to serve those regions.

TIEC argued that the proposed amendments could be read to allow for future designations of new CREZs without a firm end date. TIEC argued that the rule as amended leaves open the possibility that the commission could designate a new CREZ plan in a future proceeding, thus restarting the three-year window for exemptions from need contemplated in subsection (e)(1). TIEC proposed making clear that all future transmission investment demonstrate need, regardless of whether the project interconnects to a CREZ. TIEC asserted that it does not interpret PURA §39.904 as permitting any future CREZ proceedings, and that PURA §39.904(h) gives the commission permission to require a need finding for a CREZ project. TIEC argued that, in the alternative, the rule could be clarified to ensure that all projects filed outside the original three-year window from the prior CREZ designation docket be required to show need, and TIEC proposed language to this effect. In addition, TIEC noted a non-substantive typographical error in proposed subsection (e)(2).

In reply, EDF Renewable Energy argued that TIEC's recommendations are not necessary to fulfill the commission's stated intention and furthermore that to sunset CREZ affirmatively by rule is not appropriate.

Commission Response

The commission believes that its proposed amendments would appropriately affirm that the CREZ Order in Docket No. 33672 is complete, following the addition of the second circuit on the Sharyland Panhandle line, and indicate that all future transmission projects intended to serve a CREZ will be required to address the criteria in PURA §37.056(c)(1) and (2). The commission agrees with the comments of TIEC that by stating that, "the commission is not required to consider the factors provided by Sections 37.056(c)(1) and (2)," PURA §39.904(h) grants the commission discretion to require that projects intended to serve a CREZ demonstrate findings of adequacy and need The proposed amendments to the rule exercise this discretion by requiring that these factors be demonstrated in future projects intended to serve a CREZ. In exercising this discretion, the commission has chosen not to adopt proposed alternatives that would perpetuate the exemption for projects intended to serve a CREZ from addressing PURA §37.056(c)(1) and (2). Because the commission will require that PURA §37.056(c)(1) and (2) be addressed in future transmission projects intended to serve a CREZ, the commission need not reach the issue of whether it has the legal authority to designate additional CREZs pursuant to PURA §39.904(g). In addition as recommended

by TIEC, the commission has corrected a non-substantive typographical error in subsection (e)(2).

§25.192 – Transmission Service Rates

§25.192(h) – Accumulated Deferred Federal Income Tax (ADFIT)

OPUC and TIEC recommended that subsection (h) be amended to reflect an updated balance for accumulated deferred federal income tax (ADFIT), which are assets or liabilities that are characterized as the difference between book accounting and income tax accounting and represent a source of cost-free capital to the utility that also benefits shareholders. TIEC noted that the current rule requires utilities to reflect the impact of certain offsetting cost decreases or revenue increases that benefit customers when they update their rates to include new investments, and that commission staff accurately observed in its strawman that ADFIT adjustments are not included in the current transmission cost of service (TCOS) filing requirements. OPUC and TIEC argued that if the ADFIT balance is not updated, it could potentially overstate the interim transmission revenue requirement to be recovered in transmission rates, and thus result in artificially high customer rates. TIEC stated that reflecting changes to ADFIT will help to ensure that utilities do not over-earn in between full rate cases, which TIEC asserted has been a significant problem in recent years. OPUC provided language which would include ADFIT balances in subsection (h)(1).

ERCOT Utilities replied that including ADFIT inappropriately expands what is intended to be a limited proceeding to ensure timely recovery of transmission investment and could result in an increased cost of capital. They stated that the current rule has been well established for over fifteen years and that investors have come to rely on it as part of the regulatory scheme in Texas. In addition, ERCOT Utilities argued that requiring an update to ADFIT would ultimately have an adverse effect on the ability of utilities to acquire capital, and thus in the long run raise rates to end-use customers. ERCOT Utilities referenced Project Number 37519, in which they argued that the commission recognized the importance of interim TCOS to the cost of capital, explaining that the interim TCOS filings "enhance the ability of Transmission Service Providers (TSPs) to achieve their authorized rates of return and improve their cash ratios, thereby strengthening their financial positions and improving their access to capital at reasonable rates during a time of significant expansion in transmission infrastructure." They argued that for these reasons, utilities' ability to update TCOS on an interim basis has been viewed positively by the investment community, which have described the Texas regulatory environment as "supportive and constructive" and the interim TCOS mechanism as one that "enhances the predictability and stability of [a utility's] cash flows, a credit positive." ERCOT Utilities stated that the investment community has warned that a rating could be downgraded if a contentious regulatory environment were to develop in Texas over a prolonged period of time.

ERCOT Utilities stressed that each transmission and distribution service provider (TDSP) and TSP has had its rates set at least once through a full rate case since the provisions of §25.192 were adopted. Thus, the cost of equity in existing rates has been based upon a regulatory regime that has included the impact to utility revenue and finances of §25.192 as it currently exists. They argued that any significant change to the current calculation requirements reduces the revenue recovery amount and impacts the timely recovery of such revenues, increases risk, and makes it more difficult for the utilities to earn their authorized return. Furthermore, ERCOT Utilities asserted that such uncertainty would result in a total cost higher than the reduction in interim TCOS revenues due to the increased risk of recovery resulting from a higher cost of debt, raising cost for end-use customers. The ERCOT Utilities further stated that the commission has specifically provided in subsection (h)(3) that it will consider the effects of the interim updates when assessing the TSP's financial risk and rate of return in a rate case. They submitted that there is no reason to modify a robust interim TCOS mechanism, the evaluation of which is reflected in each utility's rate of return. They argued that this mechanism has allowed the utilities in Texas to fund necessary transmission projects for both traditional transmission projects during a period of increasing growth, as well as billions of dollars in CREZ transmission projects. The ERCOT Utilities concluded that, for these reasons, no change should be made to include ADFIT.

Commission Response

The purpose of the commission's amendments to this rule is to conform the rule to statutory changes. OPUC's and TIEC's proposed changes do not pertain to the statutory changes, and therefore the commission does not make any changes in response to these comments. Furthermore, the commission would require additional information and evaluation of the proposed changes in order to reach a decision on their substantive merits.

<u>§25.192(h) – Interim Transmission Cost of Service (TCOS) Update</u>

TIEC recommended that the commission amend subsection (h) to require that each TSP file an interim TCOS update once every 36 months. TIEC averred that TSPs currently have a unilateral discretion over the timing of filing a TCOS update, which allows TSPs to selectively file updates when they can justify a rate increase, but not when they expect a rate decrease. TIEC noted that some TSPs have continued to collect the same transmission rates from customers for decades while the underlying investments depreciate or are retired and no new investments are made. As a result, TIEC stated that TCOS charges in Texas are likely significantly inflated relative to the utilities' actual cost of service, and this concern is particularly heightened given the recent large increases in transmission rates due to CREZ and several billion dollars of reliability upgrades in ERCOT. TIEC argued that requiring periodic TCOS updates would provide a check on these ever-increasing transmission rates. TIEC stated that a mandatory TCOS update would allow customers to realize some savings from depreciation, plant retirements, and other factors that increase utility revenues or decrease costs. TIEC noted that requiring periodic TCOS updates should not create a significant burden on either the utilities or the commission, as TCOS updates tend to be processed administratively with little or no controversy.

In reply comments, ERCOT Utilities asserted that such an amendment would increase filings made by TSPs when no adjustment to their rates is necessary. ERCOT Utilities argued that the purpose of the interim TCOS process is to reduce regulatory lag by allowing utilities to place capital expenditures into rates in a more timely manner after they become used and useful than would be possible if all rate changes needed to be processed through a full base rate case. ERCOT Utilities asserted that any rates established in an interim TCOS are subject to a prudence review, true-up, and possible refund when the utility files a full rate case. ERCOT Utilities argued that TIEC's proposal belies this process by requiring an arbitrary filing unrelated to the very purpose of the rule. They stated that the interim TCOS process is not intended to be a periodic review of a utility's transmission assets, as TIEC suggests with its proposed language. ERCOT Utilities questioned TIEC's rationale that three years is the appropriate amount of time between interim TCOS proceedings. They reasoned that while one utility could have a substantial investment during a 36-month period and file multiple interim TCOS cases, another utility could have no new transmission projects for a 36-month period. The ERCOT Utilities reasoned that including such an arbitrary requirement will needlessly increase the amount of filings made by utilities whose rates do not need to be updated, and ultimately will only increase costs to ratepayers.

ERCOT Utilities further asserted that TIEC's claim that TSP's have "unilateral discretion" over when to change rates is simply not true. They stated that each year utilities file an earnings-monitoring report, and furthermore that the commission has the authority to require a utility to file a rate case if the utility is overearning. The ERCOT Utilities added that TIEC's suggestion will increase uncertainty surrounding transmission rates. They reasserted that the interim TCOS mechanism is well established and currently viewed favorably by the capital markets, and TIEC's proposed requirement would be detrimental to the utilities and ratepayers.

Commission Response

The purpose of the commission's amendments to this rule is to conform the rule to statutory changes. TIEC's proposed changes do not pertain to the statutory changes, and therefore the commission does not make any changes in response to these comments. Furthermore, the commission would require additional information and evaluation of the proposed changes in order to reach a decision on their substantive merits.

§25.192 - General Comments Regarding Strawman Proposals

TIEC included in its comments certain changes that were proposed in the strawman but omitted from the proposed amendments, including deleting an obsolete reference to the initial implementation of §25.193, and making clarifications regarding the transmission facilities and load growth revenues that must be included in the TCOS filings.

In reply comments, ERCOT Utilities noted that the proposals made by TIEC and OPUC regarding the interim TCOS mechanism, save one, were made during the strawman process and were ultimately not included by the commission in the proposal published in the *Texas Register*. They argued that the strawman process is designed to provide the commission with comments in order to, among other things, determine the scope of the rulemaking and the issues that the commission believes should be part of the formal process. ERCOT Utilities referenced a filing in Project No. 30088 in which commission staff noted that it utilizes comments to the strawman to identify important issues and make necessary changes before a rule is formally proposed for publication. ERCOT Utilities argued that many parties commented on the Strawman's possible amendments to §25.192 and that based on those comments, the commission determined that the scope of this rulemaking should not include the proposed amendments suggested by OPUC and TIEC regarding ADFIT, ERCOT exports, filing frequency, or changes to FERC accounts. ERCOT Utilities stated that if the strawman process is to properly assist the commission in formulating the scope and content of a rulemaking, and if the commission's actions in response to that process are to be meaningful, then the commission should reject TIEC's and OPUC's comments as falling outside the scope of this rulemaking. ERCOT Utilities argued that to do otherwise would render the strawman process far less useful, greatly reduce administrative efficiency, and introduce uncertainty in developing the scope of the issues. They noted that the Texas Legislature adopted various amendments to PURA during the 84th Legislative Session, including those found in SB 933, SB 776, and HB 1535, the three bills that gave rise to the instant project, and the scope of the proposed amendments are appropriately limited to matters mandated by the Texas Legislature. ERCOT Utilities commented that more specifically, while the implementation of these amendments may require changes to the commission's rule on transmission rates found in §25.192, as that rule relates to municipally owned utilities, nothing in the referenced laws explicitly changed—or even implied that any changes were necessary – to the way the commission currently calculates interim transmission rates for other TDSPs and TSPs in ERCOT. They argued that OPUC's and TIEC's suggestions go beyond implementing the Legislature's changes to PURA, and burden an already complex rulemaking with issues not germane to the notice of these proposed rule amendments.

ERCOT Utilities added that the Legislature recently provided the commission guidance on alternative rate mechanisms through Senate Bill 744, which amended PURA §36.210 to continue periodic rate adjustments for electric utility distribution investments under PURA until 2019, and required the commission to study the gamut of alternative ratemaking mechanisms and report the results of the study to the Legislature. They argued that in view of this upcoming study, it is premature to make substantive changes to existing ratemaking mechanisms before the commission concludes its report. The ERCOT Utilities concluded that, because the Legislature has not directed proposed changes to the calculation of interim transmission rates, the commission should limit this proceeding to the statutory changes and wait until the referenced report is finalized.

The ERCOT Utilities argued additionally that OPUC's and TIEC's comments are clearly outside the scope of the proposed rule, and modifying the rule could raise significant concerns under the notice requirements of the Texas Administrative Procedures Act (APA).

Commission Response

The purpose of the commission's amendments to this rule is to conform the rule to statutory changes. TIEC's proposed changes do not pertain to the statutory changes, and therefore the commission does not make any changes to the rule in response to these comments. Furthermore, the commission would require additional information and evaluation of the proposed changes in order to reach a decision on their substantive merits.

<u>§25.192(h)(1) – FERC Account Balances</u>

TIEC proposed adding language to describe the transmission facilities that are to be included in an interim update to transmission rates as those "properly recorded in FERC plant accounts 350-359." The ERCOT Utilities responded that current industry practice is to include all transmission plant that is functionalized to transmission in an interim TCOS. They pointed out that portions of FERC accounts 360-362 are functionalized to transmission and properly included in an interim TCOS, and, consistent with this practice, the interim TCOS Filing Instructions identify the FERC accounts to be included in the filing as FERC accounts 350-362 rather than only 350-359. The ERCOT Utilities stated that, additionally, transmission cost of service is described in subsection (c) as including the "commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function)." The ERCOT Utilities argued that if subsection (h)(1) is amended to specifically identify FERC plant accounts, it should be amended to identify FERC accounts 350-362 and include the parenthetical "(or accounts with similar contents or amounts functionalized to the transmission function)" for consistency and clarity.

TIEC additionally proposed language to require transmission revenues consistent with the proposed rates and properly recovered under subsection (e), which governs transmission rates for exports from ERCOT. In reply comments, the ERCOT Utilities commented that TIEC's proposed amendment would require revenue from the transmission of electricity out of the ERCOT region over the DC ties to be credited as a reduction in a TSP's TCOS. They argued that this change has no relation to the statutory changes and if changes to the manner in which the interim TCOS reflects revenues from ERCOT exports are necessary, the issue should be studied outside of this rulemaking. ERCOT Utilities stated that the relative costs of collection, compared to revenue received by each TDSP, may drive a collection mechanism different from the point-to-point billing that transmission and distribution providers use for other transmission charges. They commented that the ability of ERCOT to track the transaction may help to determine the manner of revenue collection, so alternatives should be explored prior to changing the way export revenues are treated in the interim TCOS filing.

Commission Response

The purpose of the commission's amendments to this rule is to conform the rule to statutory changes. TIEC's proposed changes do not pertain to the statutory changes, and therefore the commission does not make any changes to the rule in response to these comments.

Furthermore, the commission would require additional information and evaluation of the proposed changes in order to reach a decision on their substantive merits.

All comments, including any not specifically referenced herein, were fully considered by the commission.

These amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (West 2007 and Supp. 2015) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §35.009, which entitles an MOU to recover payments in lieu of ad valorem taxes; PURA §37.051, which requires certificates of convenience and necessity (CCNs) for MOUs or MPAs constructing transmission facilities outside of their boundaries and for persons interconnecting tie line facilities to the ERCOT transmission grid; PURA §37.058, which requires CCNs for electric generating facilities of non-ERCOT utilities; and PURA §39.904, which authorizes the commission to designate CREZs.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 37.051, 37.058, and 39.904.

§25.101. Certification Criteria.

(a) **Definitions.** The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise:

(1) **Construction and/or extension --** Shall not include the purchase or condemnation of real property for use as facility sites or right-of-way. Acquisition of right-of-way shall not be deemed to entitle an electric utility to the grant of a certificate of convenience and necessity without showing that the construction and/or extension is necessary for the service, accommodation, convenience, or safety of the public.

(2) **Generating unit --** Any electric generating facility. This section does not apply to any generating unit that is less than ten megawatts and is built for experimental purposes only.

(3) **Habitable structures --** Structures normally inhabited by humans or intended to be inhabited by humans on a daily or regular basis. Habitable structures include, but are not limited to: single-family and multi-family dwellings and related structures, mobile homes, apartment buildings, commercial structures, industrial structures, business structures, churches, hospitals, nursing homes, and schools.

(4) **Municipal Power Agency (MPA) --** Agency or group created under Texas Utilities Code, Chapter 163 – Joint Powers Agencies.

(5) **Municipal Public Entity (MPE) --** A municipally owned utility (MOU) or a municipal power agency.

(6) **Prudent avoidance --** The limiting of exposures to electric and magnetic fields that can be avoided with reasonable investments of money and effort.

(7) **Tie line --** A facility to be interconnected to the Electric Reliability Council of Texas (ERCOT) transmission grid by a person, including an electric utility or MPE, that would enable additional power to be imported into or exported out of the ERCOT power grid.

(b) **Certificates of convenience and necessity for new service areas and facilities.** Except for certificates granted under subsection (e) of this section, the commission may grant an application and issue a certificate only if it finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public, and complies with the statutory requirements in the Public Utility Regulatory Act (PURA) §37.056. The commission may issue a certificate as applied for, or refuse to issue it, or issue it for the construction of a portion of the contemplated system or facility or extension thereof, or for the partial exercise only of the right or privilege. The commission shall render a decision approving or denying an application for a certificate within one year of the date of filing of a complete application for such a certificate, unless good cause is shown for exceeding that period. A certificate, or certificate amendment, is required for the following:

(1) **Change in service area**. Any certificate granted under this section shall not be construed to vest exclusive service or property rights in and to the area certificated.

(A) Uncontested applications: An application for a certificate under this paragraph shall be approved administratively within 80 days from the date of filing a complete application if:

(i) no motion to intervene has been filed or the application is uncontested;

(ii) all owners of land that is affected by the change in service area and all customers in the service area being changed have been given direct mail notice of the application; and

(iii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(B) Minor boundary changes or service area exceptions: Applications for minor boundary changes or service area exceptions shall be approved administratively within 45 days of the filing of the application provided that:

(i) every utility whose certificated service area is affected agrees to the change;

(ii) all customers within the affected area have given prior consent; and

(iii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(2) **Generation facility.**

(A) In a proceeding involving the purchase of an existing electric generating facility by an electric utility that operates solely outside of ERCOT, the commission shall issue a final order on a certificate for the facility not later than the 181st day after the date a request for the certificate is filed with the commission under PURA §37.058(b).

(B) In a proceeding involving a newly constructed generating facility by an electric utility that operates solely outside of ERCOT, the commission shall issue a final order on a certificate for the facility not later than the 366th day after the date a request for the certificate is filed with the commission under PURA §37.058(b).

(3) **Electric transmission line.** All new electric transmission lines shall be reported to the commission in accordance with §25.83 of this title (relating to Transmission Construction Reports). This reporting requirement is also applicable to new electric transmission lines to be constructed by an MPE seeking to directly or indirectly construct, install, or extend a transmission facility outside of its applicable boundaries. For an MOU, the applicable boundaries are the municipal boundaries of the municipality that owns the MOU. For an MPA, the applicable boundaries are the municipal boundaries of the public entities participating in the MPA.

(A) Need:

(i) Except as stated below, the following must be met for a transmission line in the ERCOT power region. The applicant must present an economic cost-benefit study that includes an analysis that shows that the levelized ERCOT-wide annual production cost savings attributable to the proposed project are equal to or greater than the first-year annual revenue requirement of the proposed project of which the transmission line is a part. Indirect costs and benefits to the transmission system may be included in the cost-benefit study. The commission shall give great weight to such a study if it is conducted by the ERCOT independent system operator. This requirement also does not apply to an application for a transmission line that is necessary to meet state or federal reliability standards, including: a transmission line needed to interconnect a transmission service customer or end-use customer; or needed due to the requirements of any federal, state, county, or municipal government body or agency for purposes including, but not limited to, highway transportation, airport construction, public safety, or air or water quality.

(ii) For a transmission line not addressed by clause (i) of this subparagraph, the commission shall consider among other factors, the needs of the interconnected transmission systems to support a reliable and adequate network and to facilitate robust wholesale competition. The commission shall give great weight to:

(I) the recommendation of an organization that meets the requirement of PURA §39.151; and/or

(II) written documentation that the transmission line is needed to interconnect a transmission service customer or an end-use customer.

(B) **Routing:** An application for a new transmission line shall address the criteria in PURA §37.056(c) and considering those criteria, engineering constraints, and costs, the line shall be routed to the extent reasonable to moderate the impact on the affected community and landowners unless grid reliability and security dictate otherwise. The following factors shall be considered in the selection of the utility's alternative routes unless a route is agreed to by the utility, the landowners whose property is crossed by the proposed line, and owners of land that contains a habitable structure within 300 feet of the centerline of a transmission project of 230 kV or less, or within 500 feet of the centerline of a transmission project greater than 230 kV, and otherwise conforms to the criteria in PURA §37.056(c):

(i) whether the routes parallel or utilize existing compatible rights-of-way for electric facilities, including the use of vacant positions on existing multiple-circuit transmission lines;

(ii) whether the routes parallel or utilize other existing compatible rights-of-way, including roads, highways, railroads, or telephone utility rights-of-way;

(iii) whether the routes parallel property lines or other natural or cultural features; and

(iv) whether the routes conform with the policy of prudent avoidance.

(C) Uncontested transmission lines: An application for a certificate for a transmission line shall be approved administratively within 80 days from the date of filing a complete application if:

(i) no motion to intervene has been filed or the application is uncontested; and

(ii) commission staff has determined that the application is complete and meets all applicable statutory criteria and filing requirements, including, but not limited to, the provision of proper notice of the application.

(D) Projects deemed critical to reliability. Applications for transmission lines which have been formally designated by a PURA §39.151 organization as critical to the reliability of the system shall be considered by the commission on an expedited basis. The commission shall render a decision approving or denying an application for a certificate under this subparagraph within 180 days of the date of filing a complete application for such a certificate unless good cause is shown for extending that period.

(4) **Tie line**. An application for a tie line must include a study of the tie line by the ERCOT independent system operator. The study shall include, at a minimum, an ERCOT-approved reliability assessment of the proposed tie line. If an independent system operator intends to conduct a study to evaluate a proposed tie line or intends to provide confidential information to another entity to permit the study of a proposed tie line, the independent system operator shall file notice with the commission at least 45 days prior to the commencement of such a study or the provision of such information. This paragraph does not apply to a facility that is in service on December 31, 2014.

(c) **Projects or activities not requiring a certificate.** A certificate, or certificate amendment, is not required for the following:

(1) A contiguous extension of those facilities described in PURA §37.052;

(2) A new electric high voltage switching station, or substation;

(3) The repair or reconstruction of a transmission facility due to emergencies. The repair or reconstruction of a transmission facility due to emergencies shall proceed without delay or prior approval of the commission and shall be reported to the commission in accordance with §25.83 of this title;

(4) The construction or upgrading of distribution facilities within the electric utility's service area;

(5) Routine activities associated with transmission facilities that are conducted by transmission service providers. Nothing contained in the following subparagraphs should be construed as a limitation of the commission's authority as set forth in PURA. Any activity described in the following subparagraphs shall be reported to the commission in accordance with §25.83 of this title. The commission may require additional facts or call a public hearing thereon to determine whether a certificate of convenience and necessity is required. Routine activities are defined as follows:

(A) The modification or extension of an existing transmission line solely to provide service to a substation or metering point provided that:

(i) an extension to a substation or metering point does not exceed one mile; and

(ii) all landowners whose property is crossed by the transmission facilities have given prior written consent.

(B) The rebuilding, replacement, or respacing of structures along an existing route of the transmission line; upgrading to a higher voltage not greater than 230 kV; bundling of conductors or reconductoring of an existing transmission facility, provided that:

(i) no additional right-of-way is required; or

(ii) if additional right-of-way is required, all landowners of property crossed by the electric facilities have given prior written consent.

(C) The installation, on an existing transmission line, of an additional circuit not previously certificated, provided that:

(i) the additional circuit is not greater than 230 kV; and

(ii) all landowners whose property is crossed by the transmission facilities have given prior written consent.

(D) The relocation of all or part of an existing transmission facility due to a request for relocation, provided that:

(i) the relocation is to be done at the expense of the requesting party; and

(ii) the relocation is solely on a right-of-way provided by the requesting party.

(E) The relocation or alteration of all or part of an existing transmission facility to avoid or eliminate existing or impending encroachments, provided that all landowners of property crossed by the electric facilities have given prior written consent.

(F) The relocation, alteration, or reconstruction of a transmission facility due to the requirements of any federal, state, county, or municipal governmental body or agency for purposes including, but not limited to, highway transportation, airport construction, public safety, or air and water quality, provided that:

(i) all landowners of property crossed by the electric facilities have given prior written consent; and

(ii) the relocation, alteration, or reconstruction is responsive to the governmental request.

(6) Upgrades to an existing transmission line by an MPE that do not require any additional land, right-of-way, easement, or other property not owned by the MOU;

(7) The construction, installation, or extension of a transmission facility by an MPE that is entirely located not more than 10 miles outside of an MOU's certificated service area that occurs before September 1, 2021; or

(8) A transmission facility by an MOU placed in service after September 1, 2015, that is developed to interconnect a new natural gas generation facility to the ERCOT transmission grid and for which, on or before January 1, 2015, an MOU was contractually obligated to purchase at least 190 megawatts of capacity.

(d) **Standards of construction and operation.** In determining standard practice, the commission shall be guided by the provisions of the American National Standards Institute, Incorporated, the National Electrical Safety Code, and such other codes and standards that are generally accepted by the industry, except as modified by this commission or by municipal regulations within their jurisdiction. Each electric utility shall construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with these standards, and in such manner to best accommodate the public, and to prevent interference with service furnished by other public utilities insofar as practical.

(1) The standards of construction shall apply to, but are not limited to, the construction of any new electric transmission facilities, rebuilding, upgrading, or relocation of existing electric transmission facilities.

(2) For electric transmission line construction requiring the acquisition of new rights-of-way, electric utilities must include in the easement agreement, at a minimum, a provision prohibiting the new construction of any above-ground structures within the right-of-way. New construction of structures shall not include necessary repairs to existing structures, farm or livestock facilities, storage barns, hunting structures, small personal storage sheds, or similar structures. Utilities may negotiate appropriate exceptions in instances where the electric utility is subject to a restrictive agreement being granted by a governmental agency or within the constraints of an industrial site. Any exception to this paragraph must meet all applicable requirements of the National Electrical Safety Code.

(3) Measures shall be applied when appropriate to mitigate the adverse impacts of the construction of any new electric transmission facilities, and the rebuilding, upgrading, or relocation of existing electric transmission facilities. Mitigation measures shall be adapted to the specifics of each project and may include such requirements as:

(A) selective clearing of the right-of-way to minimize the amount of flora and fauna disturbed;

(B) implementation of erosion control measures;

(C) reclamation of construction sites with native species of grasses, forbs, and shrubs; and

(D) returning site to its original contours and grades.

(e) **Certificates of convenience and necessity for existing service areas and facilities.** For purposes of granting these certificates for those facilities and areas in which an electric utility was providing service on September 1, 1975, or was actively engaged in the construction, installation, extension, improvement of, or addition to any facility actually used or to be used in providing electric utility service on September 1, 1975, unless found by the commission to be otherwise, the following provisions shall prevail for certification purposes:

(1) The electrical generation facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise provided, to the facilities and real property on which the facilities were actually located, used, or dedicated as of September 1, 1975.

(2) The transmission facilities and service area boundary of an electric utility having such facilities in place or being actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's

system as of September 1, 1975, shall be, unless otherwise provided, the facilities and a corridor extending 100 feet on either side of said transmission facilities in place, used or dedicated as of September 1, 1975.

(3) The facilities and service area boundary for the following types of electric utilities providing distribution or collection service to any area, or actively engaged in the construction, installation, extension, improvement of, or addition to such facilities or the electric utility's system as of September 1, 1975, shall be limited, unless otherwise found by the commission, to the facilities and the area which lie within 200 feet of any point along a distribution line, which is specifically deemed to include service drop lines, for electrical utilities.

(f) **Transferability of certificates.** Any certificate granted under this section is not transferable without approval of the commission and shall continue in force until further order of the commission.

(g) **Certification forms.** All applications for certificates of convenience and necessity shall be filed on commission-prescribed forms so that the granting of certificates, both contested and uncontested, may be expedited. Forms may be obtained from Central Records.

(h) **Commission authority**. Nothing in this section is intended to limit the commission's authority to recommend or direct the construction of transmission under PURA §§35.005, 36.008, or 39.203(e).

§25.174. Competitive Renewable Energy Zones.

(a) **Competitive Renewable Energy Zone Transmission Projects.** In considering an application for a certificate of convenience and necessity (CCN) or CCN amendment for the addition of a second 345-kilovolt (kV) circuit on the Alibates-AJ Swope-Windmill-Ogallala-Tule Canyon transmission line, the commission is not required to consider the factors under Public Utility Regulatory Act (PURA) §37.056(c)(1) and (2).

(b) **Designation of Competitive Renewable Energy Zones.** The designation of Competitive Renewable Energy Zones (CREZs) pursuant to PURA §39.904(g) shall be made through one or more contested-case proceedings initiated by commission staff, for which the commission shall establish a procedural schedule. The commission shall consider the need for proceedings to determine CREZs in 2007.

(1) Commission staff shall initiate a contested case proceeding upon receiving the information required by paragraph (2) of this subsection. Any interested entity that participates in the contested case may nominate a region for CREZ designation. An entity may submit any evidence it deems appropriate in support of its nomination, but it shall include information prescribed in paragraph (2)(A) - (C) of this subsection.

(2) By December 1, 2006, the Electric Reliability Council of Texas (ERCOT) shall provide to the commission a study of the wind energy production potential statewide, and of the transmission constraints that are most likely to limit the deliverability of electricity from wind energy resources. ERCOT shall consult with

other regional transmission organizations, independent organizations, independent system operators, or utilities in its analysis of regions of Texas outside the ERCOT power region. At a minimum, the study submitted by ERCOT shall include:

(A) a map and geographic descriptions of regions that can reasonably accommodate at least 1,000 megawatts (MW) of new wind-powered generation resources;

(B) an estimate of the maximum generating capacity in MW that each zone can reasonably accommodate and an estimate of the zone's annual production potential;

(C) a description of the improvements necessary to provide transmission service to the region, a preliminary estimate of the cost, and identification of the transmission service provider (TSP) or TSPs whose existing transmission facilities would be directly affected;

(D) an analysis of any potential combinations of zones that, in ERCOT's estimation, would result in significantly greater efficiency if developed together; and

(E) the amount of generating capacity already in service in the zone, the amount not in service but for which interconnection agreements (IAs) have been executed, and the amount under study for.

(3) The Texas Department of Parks and Wildlife may provide an analysis of wildlife habitat that may be affected by renewable energy development in any candidate zone, and may submit recommendations for mitigating harmful impacts on wildlife and habitat.

(4) In determining whether to designate an area as a CREZ and the number of CREZs to designate, the commission shall consider:

(A) whether renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies;

(B) the level of financial commitment by generators; and

(C) any other factors considered appropriate by the commission as provided by PURA, including, but not limited to, the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone, and the estimated benefits of renewable energy produced in the candidate zone.

(5) The commission shall issue a final order within six months of the initiation by commission staff of a CREZ proceeding, unless it finds good cause to extend the deadline. For each new CREZ it orders, the commission shall specify:

(A) the geographic extent of the CREZ;

(B) major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect to the existing grid;

(C) an estimate of the maximum generating capacity that the commission expects the transmission ordered for the CREZ to accommodate; and

(D) any other requirement considered appropriate by the commission as provided by PURA.

(6) The commission may direct a utility outside of ERCOT to file a plan for the development of a CREZ in or adjacent to its service area. The plan shall include the maximum generating capacity that each potential CREZ can reasonably accommodate; identify the transmission improvements needed to provide service to each CREZ; and include the cost of the improvements and a timetable for complying with all applicable federal transmission tariff requirements.

(c) **Level of financial commitment by generators for designating a CREZ.**

(1) A renewable energy developer's existing renewable energy resources, and pending or signed IAs for planned renewable energy resources, leasing agreements with landowners in a proposed CREZ, and letters of credit representing dollars per MW of proposed renewable generation resources, posted with ERCOT, that the developer intends to install and the area of interest are examples of financial commitment by developers to a CREZ. The commission may also consider projects for which a TSP, ERCOT, or another independent system operator is conducting an interconnection study; and any other factors for which parties have provided evidence as indications of financial commitment.

(2) A non-utility entity's commitment to build and own transmission facilities dedicated to delivering the output of renewable energy resources in a proposed CREZ to the transmission system of a TSP in Texas or a deposit or payment to secure or fund the construction of such transmission facilities by an electric utility or a transmission utility to deliver the output of a renewable generation project in Texas is an indication of the entity's financial commitment to a CREZ.

(d) **Plan to develop transmission capacity.**

(1) After the issuance of a final order in accordance with subsection (b)(5) of this section, entities interested in constructing the transmission improvements shall submit expressions of interest to the commission. The commission shall select the entity or entities responsible for constructing the transmission improvements, establish a schedule by which the improvements shall be completed, and specify any additional reporting requirements or other measures deemed appropriate by the commission to ensure that entities complete the ordered improvements in a timely manner.

(2) The commission shall develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the CREZ.

(3) In developing the transmission capacity plan, the commission may consider:

(A) the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone;

(B) the estimated cost of additional ancillary services; and

(C) any other factors considered appropriate by the commission as provided by PURA.

(e) **Certificates of convenience and necessity.**

(1) Not later than three years after a commission final order designating a CREZ, each TSP selected to build and own transmission facilities for that CREZ shall file all required CREZ CCN applications. The commission may grant an extension to this deadline for good cause. The commission may establish a filing schedule for the CCN applications.

(2) A CCN application for a transmission project intended to serve a CREZ, except an application filed pursuant to paragraph (1) of this subsection or subsection (a) of this section, shall address all the criteria in PURA §37.056, including the criteria in PURA §37.056(c)(1) and (2).

(3) In determining whether financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ, the commission shall consider the following evidence of financial commitment by renewable generators:

(A) capacity represented by installed generation located in one or more of the counties that lie in whole or in part within the CREZ;

(B) capacity represented by generation projects under construction that are located in one or more of the counties that lie in whole or in part within the CREZ and that will be operational within six months of the final order in a financial commitment proceeding. Evidence that the project will be operational within six months may include documentation showing that a construction contractor has been hired, that preliminary site work has begun, that the project financing has closed, or similar indicators of the status of the project;

(C) capacity represented by planned generation projects that are located in one or more of the counties that lie in whole or in part within the CREZ and that have a signed IA with a TSP that has been defined in subsection (a)(2)(E) of this section designated to build and own transmission facilities for that CREZ; and

(D) capacity represented by collateral posted by generators for the CREZ that complies with paragraph (7) of this subsection.

(4) Financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ if the sum of the renewable generating capacity under any combination of paragraph (3)(A), (B), (C), and (D) of this subsection is at least 50% of the designated generating capacity for the CREZ. Fifty percent of the designated generating capacity for the Panhandle A CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,595.5 MW. Fifty percent of the designated generating capacity for the Panhandle B CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,196.5 MW.

(5) Installed renewable generation, renewable generation projects under construction, and planned renewable generation projects with signed IAs in the McCamey, Central, and Central West CREZs approved by the commission in Docket Number 33672 satisfy the financial commitment test set forth in paragraph (4) of this subsection for those CREZs and therefore financial commitment by renewable

generators for those CREZs is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for those CREZs. This finding of sufficient financial commitment shall be recognized in the CCN proceedings for transmission facilities for those CREZs and shall not be addressed further in those proceedings.

(6) Commission staff shall initiate a single proceeding for the commission to determine whether there is sufficient financial commitment under PURA §39.904(g)(3) by renewable generators for the Panhandle A and Panhandle B CREZs approved by the commission in Docket Number 33672 to grant CCNs for transmission facilities for those CREZs. If the commission determines that there is sufficient financial commitment for one of those CREZs, that finding shall be recognized in the CCN proceedings for transmission facilities for that CREZ, as identified in the commission's order in the proceeding initiated pursuant to this paragraph, and shall not be addressed further in the CCN proceedings. If the commission determines that the Panhandle A or Panhandle B CREZ does not satisfy the financial commitment test in paragraph (4) of this subsection, the commission may:

(A) consider other evidence of financial commitment that the commission finds relevant under PURA §39.904(g)(3);

(B) find that the financial commitment requirement for that CREZ has been met if the commission determines that significant financial commitment exists in that CREZ and that the CREZ is sufficiently interrelated with a CREZ that has satisfied the financial commitment test;

(C) delay the filing of CREZ CCN applications for that CREZ until the commission conducts a subsequent proceeding in which it finds sufficient financial commitment for that CREZ in accordance with the financial commitment provisions of this subsection; or

(D) take other appropriate action.

(7) A renewable generator that elects to post collateral pursuant to paragraph (3)(D) of this subsection shall comply with the following requirements:

(A) The renewable generator shall provide a letter of intent to post collateral in a proceeding conducted pursuant to paragraph (6) of this subsection. The renewable generator shall then post the collateral no later than 30 days after the commission issues an interim order finding sufficient financial commitment by renewable generators for the CREZ. If the renewable generators post sufficient collateral, the commission may enter a final order with findings that reflect the adequacy of the financial commitment for the CREZ. If the renewable generators do not post sufficient collateral, the commission may enter a final order with findings that reflect the inadequacy of the financial commitments for the CREZ.

(B) A renewable generator shall post collateral equal to $15,350 per MW of its planned project capacity, or $10,000 per MW if the capacity is supported by leasing agreements with landowners that convey a right or option for a period of at least 20 years to develop and operate a renewable energy project based on a conversion factor of 60 acres per MW for a wind energy project.

(C) A renewable generator planning to build a project in a CREZ shall post collateral with the TSP with which it will interconnect in the CREZ or, if the TSP with which it will interconnect has not been determined, with any

TSP that has been designated to build and own transmission facilities for that CREZ.

(D) A renewable generator may post collateral by providing a cash deposit, letter of credit, or guaranty agreement from an entity with an investment-grade credit rating. A TSP shall require a renewable generator that posts a guaranty agreement to provide another form of collateral if the guarantor loses its investment-grade credit rating or declares bankruptcy. If the renewable generator does not provide another form of collateral, the commission may take appropriate action including seeking administrative penalties.

(8) A TSP that receives collateral from a renewable generator pursuant to paragraph (7) of this subsection shall handle that collateral in accordance with the following provisions.

(A) If a renewable generator signs an IA with the TSP and posts any collateral required by the TSP to secure the construction of collection facilities, the TSP shall return to the generator all collateral received from that generator.

(B) If a renewable generator does not sign an IA with the TSP and post any collateral required by the TSP to secure the construction of collection facilities within 90 days after the TSP notifies it that the transmission system is capable of accommodating the renewable generator's renewable energy facility, the TSP shall retain the collateral received from the generator as an offset to the cost of the transmission facilities the TSP constructs for the

CREZ and shall take all reasonable measures to execute any non-cash collateral.

(9) In a CREZ CCN application, a TSP may propose modifications to the transmission facilities described in a CREZ order if such improvements would reduce the cost of transmission or increase the amount of generating capacity that transmission improvements for the CREZ can accommodate. The commission may direct ERCOT to review modifications proposed by the TSP.

(10) Findings in Docket Numbers 33672, 35665, and 36146 and the commission's finding in paragraph (5) of this subsection establish that the level of financial commitment is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities designated as a Default Project in ordering paragraph 1 of the Order in Docket Number 36146 and for transmission facilities designated as a Priority Project in finding of fact 136 in the Order on Rehearing in Docket Number 33672. This finding of sufficient financial commitment shall be recognized in all pending and future CCN proceedings for Default and Priority Projects and shall not be addressed further in those proceedings.

(f) **Excess development in a CREZ.** If the aggregate level of renewable energy capacity for which transmission service is requested for a CREZ exceeds the maximum level of renewable capacity specified in the CREZ order, and if the commission determines that the security constrained economic dispatch mechanism used in the power region to establish a priority in the dispatch of CREZ resources is insufficient to resolve the congestion caused by excess development, the commission may initiate a proceeding and may consider limiting interconnection to and/or establishing dispatch priorities regarding the transmission system in the CREZ, and identifying the developers whose projects may interconnect to the transmission system in the CREZ under special protection schemes.

§25.192. Transmission Service Rates.

(a) **Tariffs.** Each transmission service provider (TSP) shall file a tariff for transmission service to establish its rates and other terms and conditions and shall apply its tariffs and rates on a non-discriminatory basis. The tariff shall apply to all distribution service providers (DSPs) and any entity scheduling the export of power from the Electric Reliability Council of Texas (ERCOT) region. The tariff shall not apply to any entity engaging in wholesale storage as described by §25.501(m) of this title (relating to Wholesale Market Design for the Electric Reliability Council of Texas) (storage entity).

(b) **Charges for transmission service delivered within ERCOT**. DSPs, excluding storage entities, shall incur transmission service charges pursuant to the tariffs of the TSP.

(1) A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP), excluding the portion of coincident peak demand attributable to wholesale storage load. A TSP's transmission rate shall remain in effect until the commission approves a new rate. The TSP's annual rate shall be converted to a monthly rate. The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

(2) Payments for transmission services shall be consistent with commission orders, approved tariffs, and §25.202 of this title (relating to Commercial Terms for Transmission Service).

(c) **Transmission cost of service.** The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 (or accounts with similar contents or amounts functionalized to the transmission function) plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function), less accumulated depreciation and accumulated deferred federal income taxes, as applicable.

(1) The following facilities are deemed to be transmission facilities:

(A) power lines, substations, reactive devices, and associated facilities, operated at 60 kilovolts or above, including radial lines operated at or above 60 kilovolts, except the step-up transformers and a protective device associated with the interconnection from a generating station to the transmission network;

(B) substation facilities on the high side of the transformer, in a substation where power is transformed from a voltage higher than 60 kilovolts to a voltage lower than 60 kilovolts;

(C) the portion of the direct-current interconnections with areas outside of the ERCOT region (DC ties) that are owned by a TSP in the ERCOT region, including those portions of the DC tie that operate at a voltage lower than 60 kilovolts; and

(D) capacitors and other reactive devices that are operated at a voltage below 60 kilovolts, if they are located in a distribution substation, the load at the substation has a power factor in excess of 0.95 as measured or calculated at the distribution voltage level without the reactive devices, and the reactive devices are controlled by an operator or automatically switched in response to transmission voltage.

(E) As used in subparagraphs (A) - (D) of this paragraph, reactive devices do not include generating facilities.

(2) For municipally owned utilities, river authorities, and electric cooperatives, the commission may permit the use of the cash flow method or other reasonable alternative methods of determining the annual transmission revenue requirement, including the return element of the revenue requirement, consistent with the rate actions of the rate-setting authority for a municipally owned utility.

(3) For municipally owned utilities, river authorities, and electric cooperatives, the return may be determined based on the TSP's actual debt service and a reasonable coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the TSP's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the TSP.

(4) A municipally owned utility that is required to apply for a certificate of public convenience and necessity to construct, install, or extend a transmission facility within ERCOT pursuant to §25.101 of this title (relating to Certification Criteria)

is entitled to recover, through the utility's wholesale transmission rate, reasonable payments made to a taxing entity in lieu of ad valorem taxes on that transmission facility, provided that:

(A) The utility enters into a written agreement with the governing body of the taxing entity related to the payments;

(B) The amount paid is the same as the amount the utility would have to pay to the taxing entity on that transmission facility if the facility were subject to ad valorem taxation;

(C) The governing body of the taxing entity is not the governing body of the utility; and

(D) The utility provides the commission with a copy of the written agreement and any other information that the commission considers necessary in relation to the agreement.

(5) The commission may adopt rate-filing requirements that provide additional details concerning the costs that may be included in the transmission costs and how such costs should be reported in a proceeding to establish transmission rates.

(d) **Billing units**. No later than December 1 of each year, ERCOT shall determine and file with the commission the current year's average 4CP demand for each DSP, or the DSP's agent for transmission service billing purposes, as appropriate, excluding the portion of coincident peak demand attributable to wholesale storage load. This demand shall be used to bill transmission service for the next year. The ERCOT average 4CP demand shall be the sum of the coincident peak of all of the ERCOT DSPs, excluding the portion of coincident peak demand attributable to wholesale storage load, for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, divided by four. As used in this section, a DSP's average 4CP demand is determined from the total demand, coincident with the ERCOT 4CP, of all customers connected to a DSP, including load served at transmission voltage, but excluding the load of wholesale storage entities. The measurement of the coincident peak shall be in accordance with commission-approved ERCOT protocols.

(e) **Transmission rates for exports from ERCOT.** Transmission service charges for exports of power from ERCOT will be assessed to transmission service customers for transmission service within the boundaries of the ERCOT region, in accordance with this section and the ERCOT protocols.

(1) A transmission service customer shall be assessed a transmission service charge for the use of the ERCOT transmission system in exporting power from ERCOT based on the megawatts that are actually exported, the duration of the transaction and the rates established under subsections (c) and (d) of this section. Billing intervals shall consist of a year, month, week, day, or hour.

(2) The monthly on-peak transmission rate will be one-fourth the TSP's annual rate, and the monthly off-peak transmission rate will be one-twelfth its annual rate. The peak period used to determine the applicable transmission rate for such transactions shall be the months of June, July, August, and September.

(3) The DSP or an entity scheduling the export of power over a DC tie is solely responsible to the TSP for payment of transmission service charges under this subsection.

(4) A transmission service customer's charges for use of the ERCOT transmission system for export purposes on a monthly basis shall not exceed the annual transmission charge for the transaction.

(f) **Transmission revenue.** Revenue from the transmission of electric energy out of the ERCOT region over the DC ties that is recovered under subsection (e) of this section shall be credited to all transmission service customers as a reduction in the transmission cost of service for TSPs that receive the revenue.

(g) **Revision of transmission rates.** Each TSP in the ERCOT region shall periodically revise its transmission service rates to reflect changes in the cost of providing such services. Any request for a change in transmission rates shall comply with the filing requirements established by the commission under this section.

(h) **Interim Update of Transmission rates.**

(1) **Frequency.** Each TSP in the ERCOT region may apply to update its transmission rates on an interim basis not more than once per calendar year to reflect changes in its invested capital. Upon the effective date of an amendment to §25.193 pursuant to an order in Project Number 37909, *Rulemaking Proceeding to Amend P.U.C. Subst. R. 25.193, Relating to Distribution Service Provider Transmission Cost Recovery factors (TCRF)*, that allows a distribution service provider to recover, through its transmission cost recovery factor, all transmission costs charged to the distribution service provider by TSPs, each TSP in the ERCOT region may apply

to update its transmission rates on an interim basis not more than twice per calendar year to reflect changes in its invested capital. If the TSP elects to update its transmission rates, the new rates shall reflect the addition and retirement of transmission facilities and include appropriate depreciation, federal income tax and other associated taxes, and the commission-authorized rate of return on such facilities as well as changes in loads. If the TSP does not have a commission-authorized rate of return, an appropriate rate of return shall be used.

(2) **Reconciliation.** An update of transmission rates under paragraph (1) of this subsection shall be subject to reconciliation at the next complete review of the TSP's transmission cost of service, at which time the commission shall review the costs of the interim transmission plant additions to determine if they were reasonable and necessary. Any amounts resulting from an update that are found to have been unreasonable or unnecessary, plus the corresponding return and taxes, shall be refunded with carrying costs determined as follows: for the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the same rate of return that was applied to the transmission investments included in the update. For the time period beginning with the effective date of the TSP's rates set in that complete review of the TSP's transmission cost of service, carrying costs shall be calculated using the TSP's rate of return authorized in that complete review.

(3) **Future consideration of effect on TSP's financial risk and rate of return.** For a TSP that has increased its rates pursuant to paragraph (1) of this subsection, the

commission may, in setting rates in the next complete review of the TSP's transmission cost of service, expressly consider the effects of reduced regulatory lag resulting from the interim updates to the TSP's rates and the concomitant impact on the TSP's financial risk and rate of return.

(4) **Commission processing of application**. The commission shall process an application filed pursuant to paragraph (1) of this subsection in the following manner.

(A) **Notice and intervention deadline.** The applicant shall provide notice of its application to all parties in the applicant's last complete review of the applicant's transmission cost of service and all of the distribution service providers listed in the last docket in which the commission set the annual transmission service charges for the Electric Reliability Council of Texas. The intervention deadline shall be 21 days from the date service of notice is completed.

(B) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 21 days after an application is filed. The motion shall be served on the applicant by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the applicant or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The applicant's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not filed a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.

(C) **Review of application.** A proceeding initiated pursuant to paragraph (1) of this subsection is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition). If the requirements of §22.35 of this title are met, the presiding officer shall issue a notice of approval within 60 days of the date a materially sufficient application is filed unless good cause exists to extend this deadline or the presiding officer determines that the proceeding should be considered by the commission.

(5) **Filing Schedule.** The commission may prescribe a schedule for providers of transmission services to file proceedings to revise the rates for such services.

(6) **DSP's right to pass through changes in wholesale rates.** A DSP may expeditiously pass through to its customers changes in wholesale transmission rates approved by the commission, pursuant to §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)).

(7) **Reporting requirements.** TSPs shall file reports that will permit the commission to monitor their transmission costs and revenues, in accordance with any filing requirements and schedules prescribed by the commission.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.101, relating to Certification Criteria, §25.174, relating to Competitive Renewable Energy Zones, and §25.192, relating to Transmission Service Rates, are hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS the 15th day of JUNE 2016.

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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BRANDY MARTY MARQUEZ, COMMISSIONER

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