PROJECT NO. 34890

RULEMAKING PROCEEDING RELATING TO NET METERING AND INTERCONNECTION OF DISTRIBUTED GENERATION	§ § § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

ORDER ADOPTING NEW §25.217 AND AMENDMENT TO §25.242 AS APPROVED AT THE DECEMBER 18, 2008, OPEN MEETING

The Public Utility Commission of Texas (commission) adopts new §25.217, relating to Distributed Renewable Generation (DRG), and an amendment to §25.242, relating to Arrangements between Qualifying Facilities and Electric Utilities with changes to the proposed text as published in the June 20, 2008 issue of the *Texas Register* (33 TexReg 4771). Project Number 34890 is assigned to this proceeding.

The new §25.217 addresses interconnection, renewable energy credits, and the sale of out-flows for distributed renewable generation. The amendment to §25.242 establishes metering requirements for DRG. The rules are competition rules subject to judicial review as specified in PURA §39.001(e).

A public hearing was held on August 5, 2008, in which comments were received from Texas Energy Efficiency Partnership (TEEP), Public Citizen, and the Sierra Club. The commission also received written comments from: James and Annette Herrington; the Solar Alliance (Solar Alliance); the Texas Renewable Energy Industries Association (TREIA); the Texas Solar Energy Industries Association (TXSEIA); TXU Energy (TXU); the Alliance for Retail Markets (ARM); Henry B. Williams; Jeff and Donna Beaver; Reliant Energy (Reliant); HelioVolt; Oncor Electric Delivery Company (Oncor); Southwestern Electric Power Company, AEP Texas North

Company, and AEP Texas Central Company (collectively, AEP); Public Citizen, Environmental Defense Fund, Sustainable Energy & Economic Development Coalition, Environment Texas, and Texas Impact (collectively, Public Citizen); David Smith; El Paso Electric Company (EPE); SunPower; and the Electric Reliability Council of Texas (ERCOT).

Preamble Question

In its Proposal for Publication, the commission asked those commenting to answer the following question:

> *Should existing qualifying facilities operating under §25.242(h)(4) in areas of the state in which customer choice has not been introduced be allowed to continue to do so?*

While making different supporting arguments, TREIA, TXSEIA, Jeff and Donna Beaver, HelioVolt, Public Citizen, and SunPower all supported allowing existing qualifying facilities (QFs) to continue operating under §25.242(h)(4) in areas of the state in which customer choice has not been introduced to continue to do so. This provision gives the owner of a QF with a design capacity of 50 kilowatts (kW) or less the option of interconnecting through a single meter that runs forward and backward and provides standards for the purchase of any net production from such a facility. TREIA and TXSEIA stated that the Legislature's intent on this issue is not clear, that traditional net metering does not conflict with the market design outside of ERCOT, and that House Bill (HB) 3693 does not require any net metering agreements outside of ERCOT to be overridden by a new net metering regime designed for competitive markets. The Beavers stated that owners of renewable generation should be allowed to continue to have whatever arrangement they currently have. HelioVolt stated that the commission should use §25.242(h)(4) as a guide for net metering in all of Texas. Public Citizen stated that changing §25.242(h)(4) will expose owners of distributed renewable generation who have already made significant up-front capital investments to very real potential for financial harm. Public Citizen stated at the workshop that Ercie and Eddie Hill of Burkburnett, Texas are purchasing a 30 kW wind turbine from Wind Eagle Corporation and are "devastated that net metering is going away." SunPower urged the commission to permit such parties to renew existing agreements and to continue to use their existing meters as long as they wish.

In contrast, EPE stated that allowing existing QFs operating under §25.242(h)(4) in areas of the state in which customer choice has not been introduced to continue to do so is contrary to the plain language of HB 3693. EPE stated that HB 3693 applies to all electric utilities and transmission and distribution utilities, with no words of limitation with respect to whether or not the utility is in ERCOT or an area of the state not subject to retail competition. EPE also stated that the Legislature limited the sale of electricity by owners of distributed renewable generation in areas of the state where customer choice has been implemented, which indicates that if it had intended to limit its metering requirements it would have done so.

AEP stated that existing QFs operating under §25.242(h)(4) in areas of the state in which customer choice has not been introduced should be allowed to continue to do so, until such time as the existing agreements expire or equipment at the premises is replaced or removed. TXEIA and TXSEIA requested that the commission clarify the limitations recommended by SWEPCO before adopting this recommendation.

Commission Response

In adopting §25.213 in the current project, the commission concluded that the use of a single meter that runs forward and backward (roll-back meter) meter is inconsistent with PURA §39.914 and §39.916. 33 TexReg 3735 (2008). PURA §39.914(d) and §39.916(f) require that meters for DRG be capable of measuring in-flows and out-flows, which roll-back meters are incapable of. Sections 39.914(c) and 39.916(j) further provide that, in an area with customer choice, a DRGO and its REP may agree that the price for energy sold by the DRGO is the wholesale clearing price of the energy at the time of day that it is made available to the grid. Absent the ability to quantify out-flows, there is no basis for the DRGO and REP to determine when the energy is made available and arrive at the value of this energy in the wholesale market. PURA §39.914 and §39.916 do not differentiate the required meters by whether the meters are located in an area with customer choice. Therefore, these provisions prohibit roll-back meters in both areas with customer choice and areas without customer choice.

There are five electric utilities providing retail service in areas without customer choice: Cap Rock Energy Corporation (Cap Rock), EPE, Entergy Texas, Inc. (Entergy), Southwestern Electric Power Company (SWEPCO), and Southwestern Public Service Company (SPS). Cap Rock, EPE, and SWEPCO are subject to PURA §39.914 and §39.916, whereas Entergy and SPS are not. PURA §39.452(d) exempts Entergy from these sections, and PURA §39.402(a) exempts SPS from these sections.

However, even though PURA §39.914 and §39.916 do not apply to Entergy and SPS, PURA §§14.001, 35.061, and 38.002 give the commission the authority to limit the use of roll-back meters by Entergy and SPS in the same manner as PURA §39.914 and §39.916 limits their use for all other electric utilities. The commission adopts this approach for Entergy and SPS, because it advances the goals for renewable energy as provided in PURA §39.904 and in order to consistently treat all similarly situated DRGOs.

PURA §39.914 and §39.916 do not specify a deadline to eliminate the use of roll-back meters. As a result, the commission has discretion in the manner that it transitions existing QFs away from roll-back meters. The commission concludes that a QF operating under existing §25.242(h)(4) in an area without customer choice will be allowed to continue to use a roll-back meter until its existing contract requiring the use of a roll-back meter expires. This approach avoids affecting existing contractual rights. However, the roll-back meter must be replaced prior to the introduction of customer choice because, as discussed above, the separate metering of in-flows and out-flows are necessary to meet the requirements of PURA §39.914(c) and §39.916(j). In addition, for a QF whose contract does not require the use of a roll-back meter, the commission has established a deadline of June 30, 2009 for the electric utility to replace the meter, which is a reasonable period of time for the electric utility to meet this requirement.

General Comments

In their initial comments, ARM and AEP expressed support for §25.217, finding it straightforward, simple, and consistent with PURA §39.914 and §39.916. They went on to state that §25.213, adopted in the first phase of this proceeding, had properly rejected proposals to incorporate a concept of "net metering" that set the value of out-flows at the retail price of in-flows, and stated that this issue should not be revisited in the second phase of the project. In its public hearing testimony, TEEP stated that while the commission may be uncertain of the Legislature's intent by its use of the term "net metering," TEEP did not understand that it had been rejected. Henry B. Williams stated that the commission was creating confusion by using the term without a sufficiently clear context, stating that the term should refer only to the means by which the difference between in-flow and out-flow is determined, with billing being a separate consideration. SunPower stated that the language in PURA §39.914 and §39.916 does not preclude use of traditional net metering and asked that the commission reconsider its approach. David Smith, a manufacturer of small wind turbines, stated that HB 3693 had been hailed as a victory for his industry, but that the commission's rules were giving REPs discretion on whether and at what price out-flows would be purchased.

HelioVolt, citing low levels of solar generation in the state, stated that the commission should exercise its discretion to support continued investment in the expansion of alternative energy production. TEEP concurred in its hearing comments. Public Citizen stated that the rule would increase risk for small scale investors in an electricity market in which they were the weakest market participants, and that such investors need to be guaranteed a reasonable return on their investments through a regulated rate for the sale of their out-flows. It further stated that the commission's website, powertochoose.com, lists no service offerings by REPs to purchase out-flows. Public Citizen went on to state that the first stated mission of the PUC is to protect consumers, but that the rule protects only investor-owned utilities and transmission companies, and that state energy policy must encourage small-scale renewable energy investment in the same way that large-scale wind investment has been underwritten by the competitive renewable energy zone (CREZ) rule, or Texas will risk falling farther behind other states in small renewable energy.

Reliant stated that the deregulated market is working in Texas, and that the competitive marketplace will give DRG owners (DRGOs) negotiating power in the determination of the value of their out-flows.

TEEP stated that there were benefits to the economy, the environment, and national security associated with rapid and widespread adoption of renewable energy technologies, especially distributed renewable energy, and that energy policy in Texas should encourage renewable energy investment and innovation.

Commission Response

As discussed above, in adopting §25.213 in the current project, the commission concluded that the use of a roll-back meter is inconsistent with PURA §39.914(d) and §39.916(f). In addition, PURA does not provide for financial incentives, apart from the possibility of obtaining renewable energy credits, or guaranteed returns for DRGOs.

Consumer Protections and Disclosures

TREIA and TXSEIA stated that the commission should consider actions it could take to ensure electricity customers in all areas of the state have convenient access to accurate, comparative information regarding the out-flow buyback offers and net metering arrangements available to them. Public Citizen proposed and TXSEIA and TREIA agreed that certain customer protections be added to encourage DRG. Specifically, Public Citizen stated that the commission should require a disclosure statement in every rate contract that identifies the rate paid by the REP for energy out-flows, including whether the rate is variable and if variable, the published index on which the rate is based and the basis for adjustment; time periods for which variable rates are tracked; market clearing price of energy during the period of energy production by the customer with DRG; the time period or number of billing cycles for which energy production may be carried over to offset energy consumption; and the rate paid by the customer for energy in-flows.

ARM stated that the disclosure proposals offered by Public Citizen are more appropriately addressed in the context of pending Project Number 35768, *Rulemaking Relating to Retail Electric Provider Disclosures to Customers.*

Commission Response

The commission agrees with ARM that the disclosure requirements are more appropriately addressed in the context of Project Number 35768. The commission posed a question in the proposal for publication in Project Number 35768 relating to this topic. Therefore, the commission declines to change §25.217 to address this issue.

§25.217(b)(1)

TREIA and TXSEIA recommended removing the word "facility" as it is a defined term in §25.5 where it has a different meaning, thus creating the possibility for confusion.

Commission response

The commission agrees and has changed the rule accordingly.

HelioVolt and TEEP proposed that the term "net metering" be defined, noting that this had been recommended in comments filed during the rulemaking project for §25.213.

Commission Response

Sections 25.217 and 25.213 provide extensive provisions on metering for distributed renewable generation under PURA §39.914 and §39.916, and the commission does not believe that the definition of "net metering" would provide additional clarity in this area.

HelioVolt stated that the term "surplus energy" was not defined in either the proposed rule or §39.916 and stated that the settlement period for surplus energy should be equal to the customer's billing period and that such a definition would make net metering (a meter that runs forward and backward) available to smaller customers without contradicting the letter of the law.

Commission Response

Under HelioVolt's recommendation, if adopted, there would be no basis for time of generation to be reflected in the price of surplus energy (which can be advantageous to the DRGO), which is a required option under PURA §39.916(j). Further, the commission believes that competition is enhanced when REPs are free to craft widely varying service

offerings, and thus declines to mandate that the settlement period for surplus energy be equal to the customer billing period.

§25.217(c)(1)(A)

TREIA, TXSEIA, and Public Citizen stated that the original language of HB 3693 did not stipulate that DRG equipment have a five year warranty remaining, only that it have a five year warranty. They opined that the legislative intent was for a five year original manufacturer's warranty to be an indication of acceptable quality and reliability standards. Oncor sought confirmation that the transmission and distribution utility (TDU) would be able to rely on the DRGO or independent school district solar generation (ISD-SG) Owner to affirm the existence and duration of the warranty.

Commission Response

The commission agrees with TREIA, TXSEIA, and Public Citizen and changes the rule accordingly. The commission disagrees with Oncor that the DRGO or ISD-SG Owner's affirmation of such a warranty is sufficient. To ensure that this requirement is met, the utility cannot rely solely on such an affirmation, but must obtain adequate tangible evidence of the five-year original manufacturer's warranty.

§25.217(c)(3)

Solar Alliance and TREIA and TXSEIA recommended changing §25.217(c)(3) to refer to "a DRGO or ISD-SG Owner whose generation capacity is not more than 2,000 kW" to better track the language of PURA §39.916.

Commission Response

The commission agrees and has changed the rule accordingly.

§25.217(c)(5)

The Solar Alliance, TREIA, TXSEIA, and TEEP stated that instead of mentioning §25.242(h)(4)(C), the new §25.217(c)(5) should refer more generally to §25.242(h)(4) or §25.242(h)(2)-(4).

Commission Response

The commission agrees and has changed the rule to refer to §25.242(h)(4).

§25.217(d)

EPE recommended changes to §25.217(d) and §25.242(f) that would give a bundled utility outside ERCOT ownership of renewable energy credits (RECs) associated with power sold under this rule to that utility. EPE stated that if the commission does not allow utilities to negotiate prices for DRG energy while REPs in ERCOT have authority to negotiate, it should compensate for this disparity by requiring the transfer of those credits to the bundled utility. EPE recommended changes to §25.217(d) and §25.242(f) that would transfer to the utility all RECs associated with energy sold under §25.217 to that utility. Sun Power in reply stated that the statute does not require that outcome, and argued that transferring the RECs would reduce the incentive to install DRG in all areas. TREIA and TXSEIA stated that the existing rules regarding RECs do not require transfer of RECs to a utility that purchases energy, that there is no particular policy goal that would be met by doing so, and that doing so would work against the policy goal of encouraging distributed generation.

Commission Response

The commission disagrees with EPE. PURA §39.914 and §39.916 address the purchase of surplus electricity by the utility, and the purchase price should reflect the value of that electricity, not the value of the electricity plus the value of the associated RECs, which can be traded separately from the electricity. In addition, distributed generation facilities have the ability to obtain certification as QFs and would be entitled to compensation for energy sold to a bundled utility at up to the utility's avoided cost. The rule that is being adopted would apply the avoided cost standard to the purchase by a bundled utility of the output of a DRG or ISD-SG, whether it has obtained this certification or not. The commission believes that one of the Legislature's objectives in adopting these sections was to provide incentives for customers to invest in distributed renewable generation facilities. Consistent with this objective, the commission concludes that the DRGO or ISD-SG Owner should not be required to sell RECs as part of its sale of electricity to the utility.

Public Citizen stated that REC credits should be listed on the bill sent by the REP to the DRGO as part of a broader customer protection plan. Reliant stated that neither the transmission and distribution service provider (TDSP) nor the REP knows precisely what level of REC credits the customer will receive, since neither the TDSP nor the REP administer the REC program.

Commission Response

The commission does not believe adding REC credits to the bill content requirement is appropriate, as REC credits are not the responsibility of the REP or the utility.

Proposed §25.217(e)

The commission declines to address at this time whether DRGOs and ISD-SG Owners are required to register as power generation companies pursuant to §25.109 of this title. The commission is not addressing this issue because requiring registration of small DRGOs and ISD-SG Owners would place a burden on these entities that outweighs the public benefits of such registration. However, because the commission's legal authority to waive registration for these entities is unclear, the commission will refer the matter for legislative consideration in its Scope of Competition in Electric Markets in Texas report to the 81st Legislature. As a result, the commission has deleted proposed §25.217(e) and moved the REC generator certification requirement to §25.217(d).

Adopted §25.217(e)(1)

TREIA and TXSEIA stated that in areas of the state in which customer choice has not been introduced, the electric utility serving the load of an ISD-SG Owner should buy the net production at a value consistent with §25.242, regardless of the ISD-SG Owner's status as a QF. EPE requested that the commission reject this recommendation. EPE stated that adoption of this suggestion by TREIA and TXSEIA would create conflict between the rule and the requirements for QFs outlined in PURA, the federal Public Utility Regulatory Policies Act of 1978 (PURPA), and 18 C.F.R. 292.207 of the Federal Energy Regulatory Commission's (FERC's) regulations implementing PURPA. EPE stated that PURA §31.002 defines an "electric utility" to include: "a person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state." PURA §31.002(6)(B) exempts QFs from this definition, and §31.002(6)(J) exempts persons that furnish electric service only to themselves, their employees, or their tenants. DRG and ISD-SG facilities are not exempt from the definition of electric utility under PURA. Thus, for DRG and ISD-SG facilities in areas outside of ERCOT, such entities must self-certify as QFs before an electric utility can be required to buy their power.

Commission Response

The commission disagrees with EPE. Pursuant to PURA §31.002(6)(J)(ii), a person that sells electricity to an electric utility is not an electric utility if its generating facility is used primarily to produce electric energy for the person's own consumption

Adopted §25.217(e)(2*)*

TXU stated that the term "price" should be replaced with the term "value" to be consistent with PURA §39.914 and §39.916. It further commented that the term "price" tends to imply a specific constant monetary amount while the term "value" is representative of a fluid material worth such as an amount that varies with conditions, as is the case with market clearing price for energy (MCPE). TEEP, Reliant, and ARM concurred with TXU's requested modification. ARM recommended that, as an alternative, the language could be modified to include the phrase "price or value" rather than one or the other.

Commission Response

Consistent with PURA §39.914 and §39.916, the commission has changed "price" to "value." The commission appreciates TXU's comments, but notes that it is not always practical to draw the distinctions between the terms "price" and "value" that TXU suggests.

TEEP recommended a guaranteed minimum price that fosters investment in DRG but at the same time opined that it was the Legislature's intent to encourage rates that recognize the value of production during peak periods.

Commission Response

The commission agrees in part with TEEP. In an area with customer choice, the commission does not have the authority to impose a purchase price on the DRGO's or ISD-DG Owner's REP. A DRGO or ISD-DG Owner has a choice of REP and therefore can negotiate with more than one REP in an effort to obtain the best deal for the sale of its electricity. However, in an area without customer choice, the DRGO's or ISD-DG Owner's host electric utility will often be the only practical option to sell electricity. In areas without customer choice, the commission does have the authority to impose a purchase price on the electric utility where the DRGO or ISD-DG Owner and the electric utility do not agree to a price. The commission has set this price at avoided cost, calculated in a manner consistent with §25.242, the QF rule and 18 C.F.R 292.304. Avoided cost is an appropriate purchase price, because it is equal to the cost the electric utility would have

incurred had it not purchased from the DRGO or ISD-DG Owner. The electric utility would need to prove the reasonableness of any price above avoided cost.

ARM and Reliant Energy stated that the rule appears to impose a strict obligation on an ISD-SG owner to sell its out-flow to its REP, regardless of whether the ISD-SG owner wishes to sell any out-flow pursuant to a contract with its REP. Both parties stated that there is not obligation on the ISD-SG owner to sell out-flows in PURA §39.914(c). ARM stated that PURA §39.914(c) requires an ISD-SG owner to sell any out-flow to the REP at an agreed-upon value only if it enters into a contractual relationship with the REP for such a sale. ARM and Reliant Energy recommended a rule change that would impose the requirement in subsection (f)(2) only on ISD-SG owners "who choose to sell out-flows." TREIA and TXSEIA, on the other hand, supported the rule as proposed because it more tightly corresponds to the original language in HB 3693 and because it would require REPs serving ISD-SGs to develop means to buy back out-flows to the benefit of their school district customers with solar generation. In the view of TREIA and TXSEIA, the difference in the language regarding school districts and other customers in PURA reflects a desire by the Legislature to promote the adoption of out-flow buyback options by more REPs. TREIA and TXSEIA stated that school districts would benefit from out-flow buyback options and the rule as proposed would have a positive effect on the marketplace by encouraging the development of buyback options by a greater number of REPs. TEEP also disagreed with ARM and Reliant Energy's request to limit the rule to ISDs or others "who choose to sell." According to TEEP, the presumption of the rule should be that the DRG investor should earn a fair return and the higher the return, the better.

Commission Response

The commission agrees with ARM and Reliant that PURA §39.914(c) does not make sale of surplus electricity obligatory for school districts and adopts ARM's proposed language.

ARM recommended that the term "facility" be replaced with the term "premise" given that the REP serves the location rather than just a building or facility.

Commission Response

The commission agrees that use of the term "premises" is more appropriate, because the ISD-DG may be separate from the consuming facility served by the REP.

Solar Alliance stated that the DRGO may not necessarily be the retail customer who has the relationship with a REP or an electric utility. Solar Alliance stated that it is not appropriate to refer to the DRGO in subsections (f) and (g) in the context of sale of out-flows because it is the owner of the DRG who is the entity that has the right to sell the out-flows - not the retail customer.

Commission Response

The commission declines to address at this time whether a person other than the end-use customer may own DRGO or ISD-SG. Having third parties own DRG and ISD-SG may have a number of benefits, including tax benefits and economies of scale. However, it is unclear whether a third party could own the facilities without becoming an electric utility, with all the associated duties and responsibilities, and the commission will refer the matter

for legislative consideration in its Scope of Competition in Electric Markets in Texas report to the 81st Texas Legislature.

HelioVolt stated that the requirement that DRGOs and REPs reach an agreement on the price of out-flows would create uncertainty to a potential DRG investor because the value of the out-flow depends on the settlement profile proposed and accepted by ERCOT. REPs would have to determine the extent to which profiling of the solar DRG resource will enable them to receive full value for their purchases in ERCOT settlement before negotiating prices. Since the negotiated price could be based upon the "clearing price of energy at the time of day," negotiating and administrating a price for surplus electricity would be complicated. HelioVolt opined that the ERCOT processes for settlement that reflect time of generation for solar generation which will be developed by January 1, 2009 would ensure that REPs would benefit financially by serving solar DRGOs. However, HelioVolt questioned the extent to which this financial benefit to the REP will accrue to solar DRG customers. The end result would be to encourage installation of smaller solar DRG systems to avoid metering costs and out-flows while REPs would be saddled with customers who reduce peak consumption by installing solar DRG facilities without informing the REP. As a result, the REP would be burdened with a standard profile that ignores the installation of solar DRG and must overpay for the energy it purchases for its customers.

HelioVolt recommended a scheme based around net metering over the customer's billing period, a feed-in tariff for net surplus generation, and standard profiling of solar DRG, which it said would be easier to implement without creating undue burdens on ERCOT ratepayers, TDSPs, or

REPs. According to HelioVolt, net metering would encourage solar DRG customers to invest in slightly larger solar systems up to the level where output nets against consumption with the added benefits that the larger solar systems would reduce peak demand and the investment needed in transmission and distribution as well as put downward pressure on ERCOT energy prices during summer peak periods.

HelioVolt stated that a feed-in tariff for out-flow sales in excess of consumption could provide a default value to anchor negotiations between REPs and solar DRG customers and thereby encourage customers to reveal their plans to install solar DRG and allow REPs to claim credit for those installations in their demand profiles while discouraging REPs from “redlining” solar customers.

Reliant Energy stated that HelioVolt’s recommendation of a “feed-in tariff” directly conflicts with PURA §§39.914(c), 39.916(j), and 39.001 and should therefore be rejected. Reliant Energy commented that PURA §39.914(c) and §39.916(j) require surplus electricity to be sold to the REP at a value agreed to between the DRGO or ISD-SG and their REP. In addition, HelioVolt’s recommendation directly conflicts with PURA §39.001, which concludes that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that prices should be determined by customer choices and the normal forces of competition.

HelioVolt stated that since solar generation follows a predictable pattern, an average price could be determined that reflected the expected value of solar DRG and any difference between the default price and wholesale electricity costs (adjusted for transmission and distribution losses) could be treated like unaccounted for energy (UFE) and uplifted to ERCOT as a whole. HelioVolt contended that this is a small cost that would be dwarfed by the benefits to ERCOT consumers from increased investment in solar energy.

ERCOT expressed concerns about HelioVolt's recommendation that the difference between the default solar generation price and wholesale electricity costs, adjusted for transmission and distribution line losses be processed akin to UFE and uplifted to the ERCOT grid as a whole. ERCOT stated that HelioVolt's recommendation could potentially create a new financial relationship between ERCOT and a REP. ERCOT requested that the commission maintain ERCOT's existing market structure, in which ERCOT has financial relationships only with qualified scheduling entities (QSEs). ERCOT stated that its UFE mechanisms deal with energy mechanisms and lack the capability to allocate differences between a REP's retail contract and wholesale pricing. According to ERCOT, the new ERCOT-REP financial relationship and new UFE monetary allocation would require changes to ERCOT's systems resulting in costs to ERCOT. ERCOT stated that if HelioVolt's recommendation is found to have merit, it should be vetted through the ERCOT stakeholder process to ensure a well-balanced market decision.

Commission Response

The commission agrees with Reliant Energy that pursuant to §39.914(c) and §39.916(j) the value of surplus energy to be sold to a REP is to be established by negotiation. The commission does not have the authority to prescribe a price for this energy or require a REP to buy it.

Adopted §25.217(e)(3)

TXU proposed language to clarify the meaning of a “REP’s service.” Additionally, it proposed the addition of language to support the possibility that the agreement between the ISD-SG Owner and the REP may have alternate termination and remittance requirements that should prevail. ARM sought to clarify that the remitted “outstanding amounts” to the ISD-SG Owner or DRGO may take the form of offsetting any delinquent bill for retail service. Reliant supported ARM’s proposed modifications to these sections with the caveat that the retail customer and the DRGO are the same entity.

Commission Response

The commission agrees with TXU and ARM and adopts their proposed language with some modification.

Adopted §25.217(f)(2)

Similar to the amendment proposed for §25.217(f)(2), TXU proposed that the term “price” be replaced with the term “value” to be consistent with PURA §39.914 and §39.916 and because the term “value” is more representative of a fluid material worth such as an amount that may vary as conditions vary. Reliant Energy and ARM concurred with TXU’s proposed modification. ARM recommended that, in the alternative, the language could be modified to include the phrase “price or value” rather than one or the other.

Commission Response

Consistent with PURA §39.914 and §39.916, the commission has changed "price" to "value". The commission appreciates TXU's comments, but notes that it is not always practical to draw the distinctions between the terms "price" and "value" that TXU suggests.

Reliant Energy stated that the owner of the DRG may not live at the premises to which the DRG is interconnected and therefore proposed language that would require the DRGO to sell its out-flows to the REP that serves the load at the premises to which the DRG is interconnected rather than the REP that serves the load of the DRGO. ARM concurred with the revision proposed by Reliant Energy.

Commission Response

The commission agrees and adopts the language proposed by Reliant with slight modification.

Adopted §25.217(g)

Oncor requested that a date certain be added to transition language in the rule and recommended that March 31, 2009, be the deadline for new contracts under the new rules between existing DRGOs, ISD-SGOs, and their REPs. TDUs would then modify or replace meters for these customers appropriate for their service agreements with their REPs.

Commission Response

The commission agrees with Oncor's recommendation and has changed the rule accordingly.

Solar Alliance stated that assuming the retail customer will be the entity making the sale of outflows is inappropriate, because the owner of the DRG may not be the retail customer. EPE stated that, in situations where a DRGO is not the retail customer and wishes to use its energy to serve the retail customer and then sell the balance of the energy to the utility, then that DRGO is acting as a utility under PURA and would require a certificate of convenience and necessity before it could serve the retail customer. EPE recommended language excluding areas outside of ERCOT from the provision in §25.217(i) that allows the DRGO or ISD-SG Owner to act on behalf of the retail customer pursuant to §§25.211-25.213. TREIA and TXSEIA disagreed, and stated that third-party ownership of DRG had worked in other states. TREIA and TXSEIA recommended that the commission not address the issue regarding the status of third-party DRG as a utility in this proceeding, suggesting that this may be an appropriate legislative or commission issue at a later date.

Commission Response

The commission declines to address at this time the legality of third-party DRG. The commission has changed subsection (i) to address only the issue of a third party acting on behalf of a customer.

§25.242(f)(3)

TREIA and TXSEIA stated that the commission's proposed language changes to §25.242(f)(3) create ambiguity for QFs larger than 10 MW but interconnecting at distribution level voltages. Section 25.211 describes the interconnection requirements for DG up to 10MW. However, TREIA and TXSEIA stated that there are possible scenarios where QFs larger than 10 MW will interconnect at distribution level voltages. While these facilities are not considered DG under §25.211, the open access requirements of PURA and Subchapter I of the substantive rules allow these interconnections. Therefore, TREIA and TXSEIA believe that the original language of §25.242(f)(3) was more comprehensive and recommend that it not be altered.

Commission Response

The commission acknowledges that TREIA and TXSEIA have identified a gap in the proposed language of §25.242(f)(3); however, the commission declines to accept their recommendation that the original language of §25.242(f)(3) be retained, because §25.242(f)(3) should be updated to reflect §25.211 for interconnection with distributed generation. However, the commission has added language to fill the gap identified by TREIA and TXSEIA.

§25.242(h)

James and Annette Herrington stated that they own a 25 kW wind turbine and have a DRG interconnection agreement with Oncor using a digital meter that is read remotely and has three separate readings to measure energy produced, energy consumed, and net energy. The Herringtons said that their agreement with Oncor provides that they use the energy they produce at an equal retail rate and provide all excess to TXU for free. They stated that it is a fantasy to think that they could negotiate a price for the energy they produce. They claimed that there will be negative economic impacts on their local economy, Burkburnett, Texas, because there will be no market for renewable energy systems. They asked the commission to maintain a net metering program for units rated at 50 kW or less, inside and outside ERCOT, that allows for meters that roll forward and backward.

The Solar Alliance supported allowing existing QFs operating under §25.242(h)(4) in areas of the state in which customer choice has not been introduced to continue to do so. The Solar Alliance claimed that to do otherwise would impose an inappropriate burden on owners of distributed renewable generation. The Solar Alliance stated that unbundling issues do not exist outside of ERCOT and stated that if the commission decides that customers must change their meters, all cost should be borne by the electric utility.

TREIA and TXSEIA stated that the commission's interpretation of HB 3693's net metering language should not be imposed on any net metering customers outside ERCOT, existing or new, because the Legislature did not make clear its intent for that to happen and doing so would result in irreparable harm to customers. TREIA and TXSEIA recommended striking the proposed language in §25.242(h)(4)(C).

The Herringtons and Jeff and Donna Beaver stated that anyone that owns a renewable energy system that is rated at less than 50 kW, regardless of where they live, should be able to continue with whatever arrangement they currently have with their electric provider. Similarly, SunPower, Public Citizen, and Heliovolt stated that all existing QFs should be allowed to continue to operate under §25.242(h)(4). Heliovolt believed that existing QFs should receive retail rates for production that is purchased.

Public Citizen and Heliovolt stated that there is a very real potential for financial harm to current DRG owners outside of ERCOT if the commission does otherwise. Public Citizen stated that DRG owners made significant up-front capital investments for their systems, based on long-term financial returns made possible under existing net metering rules. Public Citizen stated that new investments would be more likely if net metering continues to be available.

TREIA, TXSEIA, and SunPower requested that the commission reject the suggestion or any interpretation of HB 3693 that the rights of QF owners must terminate at the end of their existing interconnection agreements. In addition, TREIA and TXSEIA stated that HB 3693 should not be read to supersede contracts outside of ERCOT. SunPower requested that the commission permit such parties to renew those agreements and continue to use their existing meters as long as they wish.

TREIA and TXSEIA recommended that AEP and other electric utilities be required to provide additional information about the length and expiration dates of existing interconnection contracts so that the commission can be fully informed about potential consequences of adopting AEP's recommendation. TREIA and TXSEIA also recommended that the commission clarify what constitutes a removal or replacement of equipment so as to leave little ambiguity.

Commission Response

The commission addressed above the use of roll-back meters in response to comments on its question on this issue. As stated above, the commission has concluded that a QF operating under existing §25.242(h)(4) in an area without customer choice will be allowed to continue to use a roll-back meter until its existing contract requiring the use of a roll-back meter expires. This approach avoids affecting existing contractual rights. However, the roll-back meter must be replaced prior to the introduction of customer choice because, the separate metering of in-flows and out-flows are necessary to meet the requirements of PURA §39.914(c) and §39.916(j). In addition, for a QF whose contract does not require the use of a roll-back meter, the commission has established a deadline of June 30, 2009 for the electric utility to replace the meter, which is a reasonable period of time for the electric utility to meet this requirement.

PURPA does not provide specific net metering requirements, other than the definition of "net metering" in PURPA §2621 as a "service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period." The standard in §2621 is one that a utility regulator must consider, but it has no obligation to adopt it. In contrast, PURA §39.914(d) and §39.914(f) provide specific metering requirements, namely, meters that "measure load and generator output" or "in-flow and out-flow at the point of common coupling." Thus, the commission must require metering that satisfies PURA's specific requirements, so long as is not inconsistent with PURPA.

Here, PURA requires metering that can provide the discrete measurements of in-flow and out-flow. Accordingly, the commission declines TREIA and TXSEIA's suggestion to strike the proposed language in §25.242(h)(4)(C). A meter that rolls backward and forward cannot and does not provide the discrete measurements required by PURA.

The commission does not agree with the Solar Alliance's recommendation that all costs for changing meters be borne by the utility. As required by PURA §39.914(d) and §39.914(f), §25.213(b)(6) requires that the distributed renewable generation owner pay any significant differential cost of the new metering.

§25.242(h)(7)

AEP recommended that §25.242(h)(7) be added for clarity and consistency to read:

> (h)(7) Metering Requirements. Notwithstanding subsection (h)(4), metering requirements for qualifying facilities and distributed renewable generators shall be consistent with §25.213.

TREIA/TXSEIA opposed this additional section as being unnecessary and potentially creating an additional cost on customers and utilities.

Commission Response

The commission does not believe that adding the clause proposed by AEP is necessary or provides additional clarity, and therefore does not make the recommended change.

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

The commission will recommend further steps to encourage DRG growth in the 2009 Scope of Electric Competition Report.

The new and amended rules are adopted under the PURA, Texas Utilities Code Annotated §14.002 (Vernon 2007 and Supp. 2008), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §14.001, which gives the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by PURA that is necessary and convenient to the exercise of that power and jurisdiction; PURA §35.061, which requires the commission to adopt and enforce rules to encourage the economical production of electric energy by qualifying facilities; PURA §38.002, which authorizes the commission to adopt standards relating to measurement, quality of service, and metering standards; PURA §39.101(b)(3), which provides the commission the authority to adopt and enforce rules relating to customers' right of access to on-site distributed generation; PURA §39.108(1) which provides that PURA Chapter 39 may not interfere with or abrogate the rights or obligations of any party to a contract with an investor-owned electric utility, river authority, municipally owned utility, or electric cooperative; PURA §39.914, which provides for the sale of out-flows produced by a public school building's solar electric generation panels; and PURA §39.916, which directs the commission to establish standards for distributed renewable generation.

Cross Reference to Statutes: PURA §§14.001, 14.002, 35.061, 38.002, 39.101, 39.108, 39.914, and 39.916.

§25.217. Distributed Renewable Generation.

(a) **Application.** This section applies to owners of distributed renewable generation, retail electric providers (REPs), the program administrator for the renewable energy credits trading program pursuant to §25.173 of this title (relating to Goal for Renewable Energy), and electric utilities, including transmission and distribution utilities (TDUs), but excludes river authorities that are electric utilities.

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

(1) **Distributed renewable generation (DRG) -** Electric generation equipment with a capacity of not more than 2,000 kilowatts provided by a renewable energy technology, as defined by Public Utility Regulatory Act §39.904(d), installed on a retail electric customer's side of the meter.

(2) **Distributed renewable generation owner (DRGO)** - A person who owns DRG.

(3) **Independent school district solar generation (ISD-SG**) - Solar electric generation equipment installed on the customer's side of the meter at a building or other facility owned or operated by an independent school district, irrespective of the level of generation capacity.

(4) **Independent school district solar generation owner (ISD-SG Owner)** - A person who owns ISD-SG.

(5) **Interconnection** - The physical connection of DRG or ISD-SG to an electric utility distribution system in accordance with this section and §25.211 of this title (relating to Interconnection of On-Site Distributed Generation (DG)), §25.212 of

this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation), and §25.213 of this title (relating to Metering for Distributed Renewable Generation).

(6) **Out-flow** - Energy produced by DRG or ISD-SG and delivered to an electric utility distribution system.

(c) **Interconnection.**

(1) An electric utility shall permit interconnection of DRG or ISD-SG if:

(A) the DRGO provides credible tangible proof that the DRG to be interconnected has or had an original manufacturer's warranty against breakdown or undue degradation for at least five years;

(B) the rated capacity of the DRG or ISD-SG does not exceed the electric utility's service capacity; and

(C) the DRG or ISD-SG is in compliance with applicable requirements of §25.211 and §25.212 of this title.

(2) An electric utility may disconnect a DRG or ISD-SG pursuant to §25.211(e) of this title.

(3) An electric utility shall not require a DRGO or ISD-SG Owner whose generation capacity is not more than 2,000 kilowatts and whose DRG or ISD-SG meets the standards established by this section to purchase an amount, type, or classification of liability insurance the DRGO or ISD-SG Owner would not have in the absence of the DRG or ISD-SG.

(4) An existing or prospective DRGO or ISD-SG Owner may request interconnection by submitting an application for interconnection with the electric utility. The application shall be on a form approved by the commission and processed by the electric utility in accordance with §25.211 and §25.212 of this title.

(5) Metering is addressed by §25.213 of this title and, for certain qualifying facilities, by §25.242(h)(4) of this title (relating to Arrangements Between Qualifying Facilities and Electric Utilities).

(d) **Renewable Energy Credits (RECs**). A DRGO or ISD-SG is subject to the certification requirements in §25.173 of this title to be eligible to receive RECs. Any RECs or compliance premiums resulting from the operation of DRG or ISD-SG are the property of the DRGO or ISD-SG Owner unless sold or otherwise transferred by the DRGO or ISD-SG Owner. The REC program administrator shall award the RECs or compliance premiums to the DRGO or ISD-SG Owner pursuant to §25.173 of this title. The purchase of out-flows does not automatically confer any rights of REC ownership on the purchaser.

(e) **Sale of out-flows by an ISD-SG Owner.**

(1) In areas of the state in which customer choice has not been introduced, the electric utility serving the load of an ISD-SG Owner shall buy all ISD-SG out-flows at a value consistent with §25.242 of this title.

(2) In areas in which customer choice has been introduced, ISD-SG Owners who choose to sell out-flows shall sell out-flows to the REP that serves the premises at which the ISD-SG is located, at a value to which both parties agree.

(3) If a REP's service to an ISD-SG Owner is terminated, any outstanding amounts due to the ISD-SG Owner may be used to offset outstanding bill amounts but in all cases shall be remitted by the REP no later than 30 days after the REP receives the usage data and any related invoices for non-bypassable charges.

(f) **Sale of out-flows by a DRGO.**

(1) In areas in which customer choice has not been introduced, the electric utility serving the DRGO's load shall buy all DRG out-flows at a value consistent with the requirements of §25.242 of this title.

(2) In areas in which customer choice has been introduced, DRGOs who choose to sell out-flows shall sell their out-flows to the REP that serves the premises at which the DRG is located at a value to which both parties agree.

(3) If a REP's service to a DRGO is terminated, any outstanding amounts due to the DRGO may be used to offset outstanding bill amounts but in all cases shall be remitted by the REP no later than 30 days after the REP receives the usage data and any related invoices for non-bypassable charges.

(g) **Transition provision.** Electric utilities and REPs shall make reasonable efforts to inform existing and potential DRGOs and ISD-SG Owners of their rights and obligations pursuant to this chapter, and shall change existing metering and purchase arrangements to conform to this section by June 30, 2009. However, a metering or purchase arrangement that is required by a contract that exists on the effective date of this section shall be changed to conform to this section effective the date the contract expires. The expiration date of such a contract may be extended by the DRGO or ISD-SG Owner if the existing terms of the contract give the DRGO or ISD-SG Owner the unilateral right to extend the expiration date. Notwithstanding the foregoing provisions of this subsection, a roll-back meter must be replaced no later than the date customer choice is offered in the area in which the roll-back meter is located.

(h) **Authority to act on behalf of a customer.** If any person purports to act on behalf of the retail customer pursuant to this section or §§25.211, 25.212 or 25.213 of this title, such person must demonstrate contractual authority to do so by letter of agency or otherwise.

§25.242. Arrangements Between Qualifying Facilities and Electric Utilities.

(a) **Purpose.** The purpose of this section is to regulate the arrangements between qualifying facilities, retail electric providers with the price to beat obligation (PTB REPs), and electric utilities as required by federal and state law in a manner consistent with the development of a competitive wholesale power market.

(b) **Application.** This section applies to all PTB REPs and to all electric utilities, including transmission and distribution utilities. The provisions of this section concerning purchase or sale of electricity between an electric utility and a qualifying facility do not apply to a transmission and distribution utility. This section does not apply to municipal utilities, river authorities, or electric cooperatives.

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

(1) **Avoided costs** -- The incremental costs to a PTB REP, or electric utility of electric energy, which, but for the purchase from the qualifying facility or qualifying facilities, such PTB REP or electric utility would generate itself or purchase from another source.

(2) **Back-up power** -- Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

(3) **Cost of decremental energy** -- The cost savings to a utility associated with the utility's ability to back-down some of its units or to avoid firing units, or to avoid

purchases of power from another source because of purchases of power from qualifying facilities.

(4) **Electric utility** -- For purposes of this section, an integrated investor-owned utility that has not unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Firm power** -- From a qualifying facility, power or power-producing capacity that is available pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(6) **Host utility** -- The utility with which the qualifying facility is directly interconnected.

(7) **Maintenance power** -- Electric energy or capacity supplied during scheduled outages of the qualifying facility.

(8) **Market price** -- The market-clearing price of energy (MCPE) in the balancing energy market for the Electric Reliability Council of Texas (ERCOT) congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties and fees typically applied to power generators.

(9) **Non-firm power from a qualifying facility** -- Power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(10) **Parallel operation** -- A mode of operation which enables a qualifying facility to export automatically any electric capacity which is not consumed by the

qualifying facility or the user of the qualifying facility's output. Parallel operation results in three possible states of operation at any point in time:

(A) The qualifying facility is generating an amount of capacity that is less than the customer's load. The customer is therefore a net consumer.

(B) The qualifying facility is generating an amount of capacity that is more than the customer's load. The customer is therefore a net producer.

(C) The qualifying facility is generating an amount of capacity that is equal to the customer's load. The customer is therefore neither a net producer nor a net consumer.

(11) **Purchase** -- The purchase of electric energy or capacity or both from a qualifying facility by a PTB REP or electric utility.

(12) **Purchasing utility** -- The electric utility that is purchasing a qualifying facility's capacity and/or energy.

(13) **Quality of firmness of a qualifying facility's power** -- The degree to which the capacity offered by the qualifying facility is an equivalent quality substitute for firm purchased power or an electric utility's own generation. At a minimum the following factors should be considered in determining quality of firmness:

(A) reliability of generation and interconnection;

(B) forced outage rate;

(C) availability during peak periods;

(D) the terms of any contract or other legally enforceable obligation, including, but not limited to, the duration of the obligation, performance guarantees, termination notice requirements, and sanctions for noncompliance;

(E) maintenance scheduling;

(F) availability for system emergencies, including the ability to separate the qualifying facility's load from its generation;

(G) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(H) other dispatch characteristics;

(I) reliability of primary and secondary fuel supplies used by the qualifying facility; and

(J) impact on utility system stability.

(14) **Retail electric provider with the price to beat obligation (PTB REP) --** A REP that makes available a PTB pursuant to PURA §39.202.

(15) **Sale** -- The sale of electric energy or capacity or both supplied to a qualifying facility.

(16) **Supplementary power** -- Electric energy or capacity regularly used by a qualifying facility in addition to that which the facility generates itself.

(17) **System emergency** -- A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(18) **Transmission and distribution utility (TDU)** -- As defined in §25.5 of this title (relating to Definitions).

(d) **Negotiation and filing of rates.**

(1) **Negotiated rates or terms.** Nothing in this section shall:

(A) limit the authority of any PTB REP or electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differs from the rate or terms or conditions that would otherwise be required by this section; or

(B) affect the validity of any contract entered into between a qualifying facility and a PTB REP or electric utility for any purchase before the adoption of this section.

(2) **Filing of rates.** All rates for sales to qualifying facilities, contractual or otherwise, shall be contained in the schedule of rates of the electric utility filed with the commission.

(e) **Availability of electric utility system cost data.**

(1) **Applicability.** Paragraph (2) of this subsection applies to large electric utilities whose total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. Paragraph (3) of this subsection applies to all other electric utilities.

(2) **Data request for large electric utilities.** Large utilities shall file the following data:

(A) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one, ten and 100 megawatts or not more than 10% of the system peak demand for systems of less than 1,000 megawatts. The avoided cost shall be stated on a cents-per-kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next nine years.

(B) the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding nine years.

(C) for the current year and each of the next nine years, the estimated capacity costs at completion of the planned capacity additions and planned capacity purchases, on the basis of dollars-per-kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. Such information shall be submitted in accordance with the Federal Energy Regulatory Commission Regulations, 18 Code of Federal Regulations, §292.302 and shall be sufficient for qualifying facilities to reasonably estimate the utility's avoided cost. Accompanying each filing pursuant to this rule shall be a detailed explanation of how the data was determined, including sources and assumptions employed.

(3) Special requirements for small electric utilities. Affected utilities shall, upon request:

(A) provide to an interested person comparable data to that required under paragraph (2) of this subsection to enable qualifying facilities to estimate the electric utility's avoided costs; or

(B) with regard to an electric utility that is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide to an interested person the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(4) **Filing date.** By February 15 each year, large electric utilities shall file with the commission and shall maintain for public inspection the data set forth in paragraph (2) of this subsection.

(f) **PTB REP and electric utility obligations.**

(1) Obligation to purchase from qualifying facilities.

(A) In accordance with this subsection and subsection (g) of this section, each PTB REP and electric utility shall purchase any energy that is made available from a qualifying facility:

(i) directly to the PTB REP or electric utility; or

(ii) indirectly to the PTB REP or electric utility in accordance with paragraph (4) of this subsection.

(B) Each electric utility shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within 90 days of being notified by the qualifying facility that such energy is or will be available, provided that the electric utility has sufficient interconnection facilities available. If an agreement to purchase energy is not reached within 90 days after the qualifying facility provides such notification, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the 90th day following such notice. If the electric utility determines that adequate interconnection facilities are not available, the electric utility shall inform the qualifying facility within 30 days after being notified for distribution interconnection, or within 60 days for transmission interconnection, giving the qualifying facility a description of the additional facilities required as well as cost and schedule estimates for construction of such facilities. If an agreement to purchase energy is not reached upon completion of construction of the interconnection facilities or 90 days after notification by the qualifying facility that such energy is or will be available, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the time of interconnection or the 90th day, whichever is later. Nothing in this subsection shall be construed in a manner that would preclude a qualifying facility from notifying and contracting for energy with a utility for sale of energy prior to 90 days before delivery of such energy.

(C) Each PTB REP shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within a timely fashion after being notified by the qualifying facility that such energy is or will be available.

(2) **Obligation to sell to qualifying facilities.** In accordance with subsection (k) of this section, each electric utility shall sell any energy and capacity requested to any qualifying facility located within the electric utility's service area. Each PTB REP shall also sell any energy requested to any qualifying facility; however, those sales shall be at market based rates. Nothing shall restrict the ability of any qualifying facility to purchase energy from any REP.

(3) **Interconnection.** Interconnection by a qualifying facility is addressed by Subchapter I, Division 1, of this chapter (relating to Transmission and Distribution) if the interconnection is to a transmission system and by §25.211 of this title (relating to Interconnection of On-site Distributed Generation) if the interconnection is to a distribution system, except if the interconnection is regulated by the Federal Energy Regulatory Commission.

(4) **Transmission to other electric utilities.** Transmission service provided by an electric utility in the ERCOT power region to a qualifying facility shall be governed by Subchapter I of this chapter.

(5) **PTB REP and scheduling with qualifying facilities.** A PTB REP shall use dynamic resource scheduling or responsibility transfer in ERCOT with any qualifying facility that requests such scheduling, as permitted by ERCOT. The PTB REP's cost of using dynamic resource scheduling or responsibility transfer attributable solely to purchases from qualifying facilities shall be charged to qualifying facilities that use such scheduling. If a qualifying facility uses static scheduling, the qualifying facility shall bear the costs for any imbalances resulting

from the qualifying facility's failure to submit a schedule or to comply with the schedule.

(g) **Rates for purchases from a qualifying facility.**

(1) Rates for purchases of energy and capacity from any qualifying facility shall be just and reasonable to the customers of the electric utility or PTB REP and in the public interest, and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided cost. Rates for purchase shall be based upon a market-based determination of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchase do not violate this subsection if the rates for such purchase differ from avoided cost at the time of delivery. Payments which do not exceed avoided cost shall be found to be just and reasonable operating expenses of the electric utility.

(3) A QF may agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. Rates for purchase of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products.

(h) **Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.**

(1) There shall be included in the tariffs of each electric utility standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The rates for purchases under this paragraph:

(A) shall be consistent with subsection (g) of this section, as it concerns purchases from a qualifying facility;

(B) shall consider the aggregate capacity value provided by multiple qualifying facilities with a design capacity of 100 kilowatts or less; and

(C) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(2) Terms and conditions unique to qualifying facilities with a design capacity of 100 kilowatts or less such as metering arrangements, safety equipment requirements, liability for injury or equipment damage, access to equipment and additional administrative costs, if any, shall be included in a standard tariff.

(3) The standard tariff shall offer at least the following options:

(A) parallel operation with interconnection through a single meter that measures net consumption;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production will not be metered or purchased by the utility and therefore there will be no additional customer charge imposed on the qualifying facility;

(B) parallel operation with interconnection through two meters with one measuring net consumption and the other measuring net production;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection;

(C) interconnection through two meters with one measuring all consumption by the customer and the other measuring all production by the qualifying facility;

(i) all consumption by the customer for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the customer would belong in the absence of the qualifying facility;

(ii) all production by the qualifying facility for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection.

(4) In addition, each electric utility shall offer qualifying facilities using renewable resources with an aggregate design capacity of 50 kilowatts or less the option of interconnecting through a single meter that runs forward and backward.

(A) Any consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs.

(B) Any production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) of this subsection.

(C) This option is not available if a contract for interconnection or the purchase of electricity is executed after December 31, 2008.

(5) Interconnection requirements necessary to permit interconnected operations between the qualifying facility and the utility and the costs associated with such requirements shall be dealt with in a manner consistent with Subchapter I of this chapter.

(6) The rates, terms and conditions contained in the standard tariff for qualifying facilities with a design capacity of 100 kilowatts or less shall be subject to review and revision by the commission.

(7) Except for qualifying facilities subject to §25.217 of this title (relating to Distributed Renewable Generation) requirements for the provision of insurance under this subsection shall be of a type commonly available from insurance carriers in the region of the state where the customer is located and for the classification to which the customer would belong in the absence of the qualifying facility. An enhancement to a standard homeowner's or farm and ranch owner's

policy containing adequate liability coverage and having the effect of adding the electric utility as an additional insured or named insured is one means of satisfying the requirements of this paragraph. Such policies shall in each instance be on a form approved or promulgated by the Texas Department of Insurance and issued by a property or casualty insurer licensed to do business in the State of Texas.

(i) **Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility.** Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility shall be filed with the commission based on one of the following approaches:

(1) Rates for purchases of nonfirm power may, by agreement of both the electric utility and the qualifying facility, be based on the utility's average avoided energy costs. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(2) PTB REPs and QFs may mutually agree to rates for purchases of nonfirm power that differ from the rates described in paragraph (4) of this subsection. Any such agreements shall be made on a nondiscriminatory basis. Such agreements may include provisions to prevent the potential for arbitrage.

(3) Rates for purchases of nonfirm power may, at the option of the qualifying facility, be based on the full cost at the time of delivery of decremental energy that would have been incurred by the electric utility had the qualifying facility not been in operation.

(A) The following factors should be considered in the calculation of the cost of decremental energy:

(i) fuel costs;

(ii) variable operating and maintenance costs;

(iii) line losses;

(iv) heat rates;

(v) cost of purchases from other sources;

(vi) other energy-related costs;

(vii) capacity costs, if, as a class, qualifying facilities providing nonfirm energy offer some predictable capacity; and

(viii) for short term energy purchases, the time and quantity of energy furnished.

(B) If practical, the avoided cost should be determined by calculating by time period, using the utility's economic dispatch model (or comparable methodology), the difference between the cost of the total energy furnished by both the qualifying facility and the utility, computed as though the energy furnished by the qualifying facility had been furnished by the utility, and the actual cost of energy furnished by the utility.

(C) The economic dispatch model should take into consideration the following factors:

(i) fuel costs;

(ii) variable operating and maintenance costs;

(iii) line losses;

(iv) heat rates;

(v) purchased power opportunity;

(vi) system stability; and

(vii) operating characteristics.

(D) Time periods should be hourly if the utility has an automated economic dispatch model available; otherwise the shortest reasonable time period for which costs can be determined should be used.

(E) Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(4) Rates for purchases of nonfirm power shall be based on the market price of energy at the time of sale from the QF unless other arrangements have been made in accordance with paragraph (2) of this subsection. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility. Such agreements may include provisions to prevent the potential for arbitrage.

(j) **Periods during which purchases not required.**

(1) Any PTB REP or electric utility which gives notice to each affected qualifying facility in time for the qualifying facility to cease delivery of energy or capacity to the PTB REP, or electric utility will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, including resource ramp rate limitations that could cause imbalances or the amount of energy put by the QF exceeds the PTB REP's load, purchases from

qualifying facilities will result in costs greater than those which the electric utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, provided, however, that this subsection does not override contractual obligations of the PTB REP or electric utility to purchase from a qualifying facility.

(2) Any PTB REP or electric utility which fails to give notice to each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the PTB REP or electric utility will be required to pay the same rate for such purchase of energy or capacity as would be required had the period of greater costs not occurred.

(3) A claim by PTB REP or an electric utility that such a period has occurred or will occur is subject to such verification by the commission either before or after the occurrence.

(k) **Rates for sales to qualifying facilities.**

(1) General rules.

(A) Rates for sales to qualifying facilities shall be just and reasonable and in the public interest, and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for standby or other supplementary service shall be based on the amount of capacity contracted for between the qualifying facility and the electric utility, and shall not penalize electric utilities that also purchase power from qualifying facilities. The need for and cost responsibility for special equipment or system modifications shall be determined by application of Subchapter I of this chapter.

(B) Rates for sales that are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the electric utility's other customers with similar load or other cost-related characteristics.

(2) Additional services to be provided to qualifying facilities.

(A) Upon request of a qualifying facility within its service area, each electric utility shall provide:

(i) supplementary power;

(ii) back-up power;

(iii) maintenance power; and

(iv) interruptible power.

(B) An electric utility shall not be required to provide supplementary power, back-up power, or maintenance power to a qualifying facility if the commission finds that provision of such power will:

(i) impair the electric utility's ability to render adequate service to its customers; or

(ii) place an undue burden on the electric utility.

(3) Rates for sales of back-up power and maintenance power. The rate for sales of back-up power or maintenance power:

(A) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(B) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(l) **System emergencies.**

(1) **Qualifying facility obligation to provide power during system emergencies.** A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(A) provided by agreement between such qualifying facility and electric utility; or

(B) ordered under the Federal Power Act, §202(c).

(2) **Discontinuance of purchases and sales during system emergencies.** During any system emergency, an electric utility may discontinue:

(A) purchases from a qualifying facility if such purchases would contribute to such emergency; and

(B) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

(m) **Enforcement.** A proceeding to resolve a dispute between an electric utility, PTB REP and a qualifying facility arising under this section may be instituted by filing of a petition with the commission. Electric utilities, PTB REPs, and qualifying facilities are encouraged to engage in alternative dispute resolution prior to the filing of a complaint.

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 §25.217, relating to Distributed Renewable Generation (DRG) and an amendment to §25.242, relating to Arrangements between Qualifying Facilities and Electric Utilities are hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS this the ________ day of DECEMBER 2008.

PUBLIC UTILITY COMMISSION OF TEXAS

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BARRY T. SMITHERMAN, CHAIRMAN

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DONNA L. NELSON, COMMISSIONER

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KENNETH W. ANDERSON, JR., COMMISSIONER

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