PROJECT NO. 26376

RULEMAKING PROCEEDING ON WHOLESALE MARKET DESIGN ISSUES IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING NEW §25.501
AS APPROVED AT THE AUGUST 21, 2003 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts new §25.501, relating to Wholesale Market Design for the Electric Reliability Council of Texas, with changes to the proposed text as published in the May 23, 2003 issue of the *Texas Register* (28 TexReg 4033). The rule is expected to yield important benefits, such as a reduction in local congestion costs; reduced opportunities for gaming and manipulation in the wholesale electricity market; increased price transparency and liquidity in the wholesale electricity day-ahead energy market; increased locational price transparency for resources; more efficient and transparent dispatch of resources in real-time; improved siting of new resources; and a reduction in the amount of new transmission facilities needed to support the reliability of, and competition in, the wholesale electricity market. These benefits will provide participants in the wholesale and retail markets with more accurate wholesale prices, which will facilitate better-informed price responses by customers in those markets. More accurate pricing will lead to more efficient consumption decisions by end-use customers, and the rule may lead to large-scale deployment of advanced demand-response technologies and distributed generation resources, more sophisticated services, and increased efficiency in the consumption of electricity.

The new rule sets forth basic principles for the ancillary service markets operated by the Electric Reliability Council of Texas (ERCOT), including both energy and ancillary capacity service markets. The rule includes requirements for ERCOT to allow market participants to self-schedule and bilaterally contract for energy and ancillary capacity services, to the extent consistent with system reliability; to require the submission of resource-specific bid curves for energy and ancillary capacity services that ERCOT competitively procures a day ahead of an operating day or in the operating day; to directly assign all congestion rents to the resources that caused the congestion; and to use nodal energy prices for resources and zonal energy prices for loads.

A public hearing on the proposed section was held at commission offices on Tuesday, June 24, 2003. Representatives from a number of entities attended the hearing; however, none provided comments at the public hearing.

The commission received comments on the proposed rule from the following entities: ERCOT; Office of Public Utility Council (OPC); Reliant Resources, Inc. (Reliant); TXU Portfolio Management Company LP and TXU Energy Retail Company LP (collectively TXU); City Public Service of San Antonio (San Antonio); City of Austin d/b/a Austin Energy (Austin); Bryan Texas Utilities (Bryan); Lower Colorado River Authority (LCRA); CenterPoint Energy Houston Electric LLC and Texas Genco LP (collectively CenterPoint); Cap Rock Energy Corporation, Inc. (Cap Rock); South Texas Electric Cooperative, Inc. (STEC); Texas Industrial Energy Consumers (TIEC); the power-generation companies and power-marketing business units of American Electric Power Company, Inc. (collectively AEP); Occidental Power Marketing, L.P (Oxy); Denton Municipal Electric and the City of Garland (Denton/Garland); Exelon Corporation (Exelon); Texas Electric Cooperatives (TEC); Magic Valley Electric Cooperative, Inc., Mid-Tex Generation & Transmission Electric Cooperative, Inc., and Rayburn County Electric Cooperative, Inc. (collectively Magic Valley, Mid-Tex, and Rayburn); Alliance for Retail Markets (ARM), comprising Constellation NewEnergy, Inc., Green Mountain Energy Company, Strategic Energy, LLC, Utility Choice Electric, APS Energy Services Company, Republic Power, LP, and Texas Commercial Energy; and Competitive Power Advocates (CPA), including American National Power, Inc., Calpine Central, L.P., Constellation Power Source, Inc., Dynegy Inc., FPL Energy, LLC, TECO Power Services Corporation, Coral Power, LLC, Mirant Americas Energy Marketing, LP, Tractabel Energy Marketing, Inc., Gregory Power Partners, L.P., PSEG Global, and Texas Independent Energy.

Comments on preamble questions

The commission requested comments on five questions related to the development of the final rule. The parties' responses to those questions and the commission's responses are summarized below.

Question 1: In subsection (e) of the proposed rule, the implementation date for this new market design is March 1, 2006. The commission seeks comment on the appropriateness and feasibility of this date.

(a) Is this deadline feasible? If not, why not, and what is your alternative implementation date?

Comments

Magic Valley, Mid-Tex, and Rayburn recommended that the commission give serious thought to delaying the implementation of the proposed rule until sufficient generation and transmission infrastructure could be added so that customers in load pockets can have the benefits of real competition for their loads.

Commission response

The commission disagrees with Magic Valley, Mid-Tex, and Rayburn that implementation of the proposed rule should be delayed until sufficient generation and transmission infrastructure has been built to address load pockets. The ERCOT grid had a number of load pockets prior to the opening of retail competition in 2002. The commission notes that wholesale and retail competition in ERCOT have provided many customers in ERCOT with lower prices and a wider range of services despite the presence of some load pockets. The commission does not want to deny the benefits of

Texas Nodal (the market design that will result from this rule) throughout ERCOT until all load pockets are removed.

The commission and stakeholders will be addressing the issue of load pockets in several ways under Texas Nodal. First, a rulemaking project, Project Number 27917, *Rulemaking on Pricing Safeguards for ERCOT-Operated Wholesale Markets,* to implement subsection (j) of the final rule (subsection (d)(7) of the proposed rule), will develop the means to mitigate bids to prevent the exercise of market power in load pockets while maintaining price signals that will encourage the siting of new generation in the load pocket. Second, the protocols implementing the rule can and should address load pocket issues through the creation of appropriately designed settlement zones for load. Large load zones that average load node prices would result in consumers in load pockets paying the same price for energy as consumers in other areas. Furthermore, under subsection (m) of the final rule, the commission has made clear that ERCOT must obtain commission approval for the initial load zones for Texas Nodal. Third, the commission will continue to address load pockets through transmission construction to reduce the congestion that results in load pockets. However, the commission and ERCOT likely will never be able to completely eliminate all load pockets, due to load growth, the limited availability of right-of-way in urban areas for new transmission facilities, the long timeline for building new transmission lines, and the substantial cost of transmission facilities.

Comments

Bryan commented that while the deadline might be feasible for some or all of the changes, the real issue was the process. Bryan stated that there should be more study and analysis, there should not be a date certain, in order to avoid the pitfalls of the previous market's implementation, and there should be adequate testing of systems before a change is implemented. Bryan also stated that retail customers must see the benefit in changes to market structures and strongly urged the commission to ensure that retail customers are the primary beneficiaries of the market changes.

STEC cautioned that consensus cannot be reached if stakeholders are given only six months to develop the Texas nodal model. STEC and Austin stated that it is important to allow for sufficient time so that every stakeholder concern is considered and addressed and to ensure that the strongest consensus is reached. STEC also stated that such a consensus will produce greater stability in the ERCOT market by reducing the risk of future litigation concerning the model adopted and will help alleviate controversy over the matter during the commission sunset process. STEC suggested that the timeline provide at least one year, and at most 18 months, for stakeholders to develop the model. STEC expressed the belief that the democratic process, in which issues can be fully explored, compromise sought, and consensus reached, will be undermined by the short time frame allowed. As an additional reason to extend the timeline, STEC noted that a lack of resources would limit the ability of some market participants to attend meetings.

STEC recommended that the implementation timeline be extended for six months to one year past March 1, 2006.

Austin recommended that the initial phase of developing a wholesale market model be extended by three months, stating that this phase will be the most difficult. San Antonio concurred that there needed to be more flexibility in the timeline for initial design, and recommended that the January 1, 2004 date be removed altogether. Instead, San Antonio suggested, July 1, 2004 should be the date for the submission of initial protocols and that all details of the new design should not be set in stone on that date.

Austin echoed the importance of providing the opportunity for all market participants to be involved in the process. Austin stated that the design phase will be the most challenging part of the process and recommended including at least an additional three months to this critical period of the timeline for education on nodal markets and alternative models because of the market participants' disparate levels of experience and knowledge regarding nodal markets. Austin opined that this education would help facilitate participation of entities with limited familiarity with nodal issues. Denton/Garland likewise noted the need for education to level the playing field.

In reply comments, CPA agreed with Austin that education of the market is worth spending time on and suggested that the protocol phase be shortened by three months to accommodate both education of the market and the March 1, 2006 completion date.

ARM shared the concerns of STEC, Austin, TXU, and others that the current timeline for the initial market design is unreasonable, especially for resource-constrained entities. ARM not only supported extending the deadline for the initial market design until the end of first quarter 2004, but also supported additional flexibility as needed to finalize the market design.

San Antonio stated that the March 1, 2006 implementation date *may* be feasible, but reminded the commission that the lesson learned from the prior wholesale and retail market design and implementation was that hard implementation dates are not the best recipe for success. San Antonio indicated that moving ahead with the process regardless of whether the milestones were actually reached within the time frame has proven in the past to be less than prudent. Austin also cited the prior market design and implementation process as a lesson that deadlines should not be allowed to drive substance. Denton/Garland also suggested that the commission be mindful of the problems that resulted when a predetermined implementation date was set prior to determining the implementation details. Cap Rock also pointed to the prior market's implementation to illustrate that while the March 1, 2006 deadline might be feasible for some or part of the proposed changes, deadlines are not prudent and do not always accommodate the testing required to fully troubleshoot the systems involved. Cap Rock argued that by avoiding a date certain, essential studies, cost-based justifications for all market participants, and allocation of any costs equitably and fairly to all market participants can be performed before a new design is implemented.

LCRA asserted that the feasibility of the deadline depends on the market design adopted. LCRA observed that should the market design be evolutionary in nature, implementation would take less time than if the market adopts a totally new design.

San Antonio recommended that the commission maintain flexibility in the ultimate implementation date by setting a date as a clear goal, but making it contingent upon the successful completion of the required milestones. CenterPoint concurred that implementing a project as complex as the one proposed requires the successful completion of milestones before proceeding with the next step. Austin agreed with the necessity of having flexibility in the implementation date, and stated that the true difficulty of designing the new market will not be fully known until deep into the process and that there is a possibility that overly restrictive deadlines could hamper the development of the best market possible. Austin also suggested that there be sufficient time for the ERCOT Board and the commission to review and fully understand the design, to consider the complete implications of the design, to provide feedback, and to consider and approve revisions.

ARM indicated that the March, 1 2006 deadline was aggressive and should be extended by six months. ARM commented that this would accommodate a reasonable length of time (two years) after the commission approves the protocols implementing the new market design. ARM stated that its members need the additional time to allow longer-term contracts to expire or be adjusted to reflect the effects of the new market design on those contracts. ARM explained that the value of those would be affected by the cost-shifting that will occur under the nodal design and that a proper transition period will reduce the risks to retail electric providers (REPs). ARM also suggested that the transition period have a defined implementation timeline and that the old structure be maintained and operated while the systems are being designed and tested. ARM continued by stating that, in particular, parallel operation of settlement systems for zonal and nodal models must occur during the testing period and that this testing/debugging period should occur, at a minimum, over a full year. ARM suggested that this period of time would help to ensure that the problems that were experienced during the opening of the retail market would not be repeated. ARM also said that ERCOT should publish the "shadow market data" to allow all market participants to analyze and scrutinize the results.

In reply comments, Magic Valley, Mid-Tex, and Rayburn fully supported ARM's recommendation of having two years pass after commission approval of the design before the implementation and extensive market testing.

In reply comments, CPA proposed that AEP's suggested load-aggregation hub development could be a way for REPs to accommodate a market implementation date sooner than two years from commission approval.

ERCOT stated that it would endeavor to meet the March 1, 2006 deadline, but that a firm implementation date is not prudent and may not be feasible, and that implementation should be driven by the achievement of project milestones. ERCOT argued, however, that firm dates for the design development and protocol approval are feasible and should be set.

OPC stated that the March 1, 2006 implementation deadline was feasible, but that the January 1, 2004 market design deadline would be difficult to meet and should be extended, and that the March 1, 2006 deadline would cause other problems for the commission.

Denton/Garland stated that the deadline is feasible in that some sort of market design changes could be made, but questioned whether a good market design could be implemented within that timeframe. TXU agreed that while the deadline might be feasible for designing and implementing a Texas nodal design, it might not be the best nodal market design. Denton/Garland also commented that a long testing phase should be included and that a mock market would help those market participants unfamiliar with locational marginal pricing (LMP) markets train their personnel and eliminate knowledge gaps that might disadvantage such market participants relative to those who have LMP experience.

Reliant deemed the timeline aggressive, but feasible. Reliant cautioned, however, that there should be sufficient time (potentially one year) for testing the system and training market participants.

CPA accepted the commission's proposed timeline and suggested that given the right direction, parts or all of Texas Nodal could be achieved earlier. AEP and Exelon agreed, stating that not only is the date feasible, but that AEP would support an opportunity to implement the new market design prior to March 1, 2006. To that end, AEP recommended that the rule provide for this possibility.

In reply comments, Magic Valley, Mid-Tex, and Rayburn strongly disagreed with CPA's "damn the torpedoes" view, and recommended that the commission assess the likely winners and losers and take measures to mitigate, at least for some period, any significant negative impacts on any sectors or locations.

In reply comments, TXU agreed with the many market participants who implored the commission to look at the lessons of the past and to ensure that there is adequate time in the timeline to design the market well and not have the process constrained by hard deadlines.

Commission response

The commission agrees with many of the parties that additional time is needed to design and implement Texas Nodal. Accordingly, the commission extends the deadline for filing the protocols by four months, from July 1, 2004 to November 1, 2004, and extends the final implementation date by seven months from March 1, 2006 to October 1, 2006.

The revised timeline in the rule is necessary to provide adequate time to design a Texas nodal model that will be sustainable in the long term. The commission agrees with parties that the additional time, particularly during the initial design stage, will be critical to facilitate the involvement of all market participants and to encourage consensus building in the implementation of the rule. The commission has decided not to include a deadline in the rule for completion of the conceptual and detailed design, but expects the design to be completed by April 2004, in order to have the protocols filed by November 1, 2004. The completion of the conceptual and detailed design will be a critical milestone that should not be delayed. Nonetheless, the commission believes that it is appropriate to provide additional flexibility in the rule to accommodate changing circumstances. For instance, it may be appropriate to spend additional time on the conceptual and detailed design and less time on developing the actual protocol language, as suggested by CPA. The commission agrees with Austin that the initial design stage will likely be the most contentious and challenging. By providing the additional time up-front for developing the conceptual and detailed design, the commission and market participants may avoid spending time and resources on the litigation of contested issues during the review and approval of the protocols.

The commission is sympathetic to the concerns regarding the impact of the timeline on the involvement of resource-constrained entities, as well as those entities that are unfamiliar with the details of a nodal market. The commission believes that the revised timeline will better accommodate greater participation of such entities in the stakeholder process.

The commission finds that the two deadlines in the rule are necessary to keep the process moving forward. The commission declines to include additional milestones in the rule, but in developing the revised timeline, the commission has considered the necessary milestones, including conceptual and detailed design, protocol development, cost-benefit analysis, and software development, integration, and market testing, as well as market participant testing. The commission anticipates that the conceptual and detailed design will be completed by April 2004 and the protocols will be approved in April 2005. Thereafter, ERCOT and market participants will have approximately one year (i.e., until April 2006) for completing software developments, integration, and testing, with market testing by participants occurring between January 2006 and September 2006. While the commission finds that it is important to provide some flexibility concerning individual milestones, it is important to stay on schedule to ensure that there is adequate time at the end for system development and testing. Based in part on the experience with the transition to a single control area in 2001 and the implementation of retail competition in ERCOT in 2002, the commission is well aware of the importance of testing to ensure that ERCOT's and market participants' systems are compatible and are functioning as intended.

The October 1, 2006 deadline for complying with the rule will give the market two years from the end of the protocol-development phase to the implementation date. This date does not accommodate a two-year period from commission approval of the protocols, but the commission believes that there will be enough information available about the future market structure at that point to facilitate contracting activities. The commission also notes that the rule does not preclude stakeholders from finalizing an activity and moving on to the next phase ahead of the deadline, as suggested by CPA.

As explained below with respect to the cost-benefit analysis for the rule, the current ERCOT wholesale market design is inefficient, produces unnecessary costs, and fails to send adequate locational price signals for the siting of resources. Consequently, it is very important to balance the need for sufficient time to redesign the market with the need to promptly eliminate the flaws in the current market. The deadlines in the final rule strike the appropriate balance between these two competing interests. As to the concerns about meeting hard deadlines, the commission believes that it has provided adequate time to meet the deadlines. Furthermore, the commission expects ERCOT and its stakeholders to work diligently to meet the deadlines in the rule and believes that the deadlines are necessary to help ensure such diligence.

(b) Is having the new market design implemented before the end of the price-to-beat period important?

Comments

STEC stated that while implementation of Texas Nodal before the end of the price-to-beat period may be important, it should not be the overriding consideration. According to

STEC, having a faulty plan can cause more problems in the long run than will result from having the plan implemented after the end of the price-to-beat period.

ARM commented that while it understands the commission's desire to protect consumers from rate shock, requiring the transition to overlap the price-to-beat period will simply place the entire risk of cost-shifting on the affiliated and competitive REPs. ARM stated that, at worst, the affiliated REP would be forced to serve customers in congested areas at a loss, and competitive REPs would lose the ability reasonably to market to them. ARM suggested that the best way to resolve this issue would be to create larger load zones and spread the costs over a greater number of customers.

Cap Rock and Bryan also agreed that making any changes before the price-to-beat period expires may negatively affect headroom and create market uncertainty. Denton/Garland agreed and added that the reduced headroom would make certain areas unattractive for competitive REPs to serve, resulting in reduced customer choice.

LCRA commented that there is significant benefit to implementing any design modifications while the safety net of the price-to-beat period still exists. LCRA suggested that introducing the new market at the same time the price-to-beat regime expires could be risky and destructive for retail competition.

TXU stated that it is very important that the new market design *not* be implemented before the end of the price-to-beat period because of the threat to retail competition in import-constrained areas caused by a considerable risk that headroom would decrease. TXU indicated that, should the commission find that the Texas nodal model will provide significant benefits to Texas customers, there is no need to protect them from the Texas nodal market by implementing the market redesign before the end of the price-to-beat period.

Magic Valley, Mid-Tex, and Rayburn agreed that while waiting until the end of the price-to-beat period would allow TXU to pass along the costs to retail customers, it would not make the costs go away because there would be more cost shifting than cost reduction.

In reply comments, Exelon was sympathetic to the concerns of parties about the implementation of the Texas nodal system before the end of the price-to-beat period. Exelon suggested that it is impossible to predict exactly what impacts the changes would have on market participants and that it is highly possible that cost savings from the more efficient dispatch throughout ERCOT would offset any increased costs reflected in LMPs. Exelon suggested that there would be mechanisms by which to mitigate the impacts during a transition period.

AEP stated that the market would benefit from an expeditious implementation of the new design and that the development of load aggregation hubs could facilitate the transition if it takes place before the end of the price-to-beat period. AEP stated that these hubs could be retained by ERCOT for purposes of contract settlement for as long as required by market participants.

CPA encouraged the commission to implement Texas Nodal prior to the end of the price-to-beat period, because doing so would enable a smoother transition. In its reply comments, ARM strongly disagreed and stated that some REPs and customers will be in for a bumpy ride if the new design is implemented before the end of the price-to-beat period.

OPC observed that while the design should be created prior to the end of the price-to-beat period, the implementation of the design should occur after that date. OPC expressed concern that since the price to beat envisions one price for every transmission and distribution utility (TDU) footprint and the rule calls for congestion pricing to be at a zonal level for load, there would be pressure on the commission to lower or raise rates accordingly due to the disparate nature of costs where zonal boundaries no longer matched-up with the TDU boundaries. OPC feared consumers would be unlikely to understand the disparity between price-to-beat rates when previously they experienced identical rates within a footprint.

Reliant stated that Texas Nodal should be implemented when it was completed and if that occurred before the end of the price-to-beat period, there should be a proper adjustment of the non-bypassable charges to maintain the competitive goals of Senate Bill 7 (SB7) (Act of May 21, 1999, 76th Leg., R.S., ch. 405, 1999 Tex. Gen. Laws 2543).

Commission response

The commission concurs that the timing of the Texas Nodal implementation in relation to the end of the price-to-beat period is an important issue. It is not, however, the only important issue and should not be the overriding determiner of the appropriate implementation date. The commission also agrees that it will need to work with stakeholders to address a number of issues and emphasizes the need to be pro-active in this regard.

The commission finds that there is an adequate opportunity to mitigate the effects of the Texas Nodal implementation date as it relates to the end of the price-to-beat period. REPs can mitigate their risk more fully because they have notice of the changes, and the commission expects their behavior to start changing in the marketplace long before the start date of Texas Nodal. In addition, the commission stresses the importance of appropriately designing settlement zones for load. Large load zones that average load node prices would reduce the potential impacts on individual retailers. The commission agrees with ARM that the size of the load zones will be a critical factor in mitigating the cost of serving customers in congested areas. Consequently, under subsection (m) of the final rule, the commission has made clear that ERCOT must obtain commission approval for the initial load zones for Texas Nodal. In addition, pricing safeguards, as required by subsection (j) of the final rule (subsection (d)(7) of the proposed rule), can mitigate the bids of resources that have local market power. In addition, any increases to the ERCOT administrative fee as a result of implementing Texas Nodal should be a relatively small part of the delivered cost of power and could be reduced by financing alternatives available to ERCOT.

As indicated above in the discussion of part (a) of question 1, the primary reason for the October 1, 2006 implementation deadline for the market redesign is that deadline appropriately balances the need to promptly implement the market redesign in order to eliminate the flaws in the current design with the need to provide adequate time to develop and implement the redesign. Nevertheless, consistent with the comments of LCRA and CPA, the commission believes that it is beneficial to implement Texas Nodal a few months before the end of the price-to-beat period, so that the risk of short-term transitional problems associated with implementation of Texas Nodal will be borne by REPs rather than retail customers eligible for the price-to-beat. The commission believes that this allocation of risk is appropriate, because the REPs are better able to minimize and control these risks than are the small retail customers that are eligible for the price-to-beat.

(c) If you believe that the new market design should be implemented in 2007 or later, what "no regrets" interim measures should be taken to address the existing problems in the current wholesale market design, such as operational inefficiency, stability of zonal boundaries, the DEC game, the uplift of local congestion costs, and inadequate price signals for siting resources?

Comments

LCRA stated that the Zonal-ERCOT-Nodal (ZEN) model is a "no regrets" item that addresses all the existing problems in subsection (c) of the proposed rule. LCRA added that since the potential benefits of ZEN exceed those of other nodal models, it is more than an "interim" measure.

STEC stated that operational efficiencies can be addressed during the interim and suggested that ERCOT's use of security-constrained economic dispatch should be high on the priority list. STEC also proposed considering the treatment of entities that have built generation and transmission prior to competition to serve their customers but are given out of merit order energy (OOME) down instructions. STEC stated that the elimination of OOME Down payments could be devastating to these entities. STEC agreed that these entities should not make a profit when complying with OOME Down instructions, but that they should be made whole so that their customers do not suffer.

San Antonio stated that the ERCOT committee process is the appropriate forum to identify and address "no regrets" issues. San Antonio suggested that any interim measure that is not embraced by the majority of ERCOT stakeholders and, therefore, may require implementation by order of the commission, would be difficult to characterize as a "no regrets" measure, in that, by definition, one or more parties will experience some regret. CPA agreed with San Antonio in reply.

CenterPoint argued that most if not all of the perceived problems had been solved or are being addressed, and suggested that it believes that the process signals provided in the zonal model suffice for new generation siting because environmental constraints and the availability of land, water, air, and fuel are the predominant drivers for siting decisions.

In reply comments, CPA strongly disagreed with CenterPoint that given time the current market structure can produce the effects sought by commission staff at a lower cost. CPA stated that ERCOT and market participants have been working on fixes for two years and have not solved the problem of ERCOT not knowing the level at which units are dispatched and where they will be operating in the current system of portfolio generation management.

ERCOT stated that it has many projects underway for delivery in 2004, and that most of them should be completed. As examples, it cited modifying the Energy Management System, developing the Enterprise Data Warehouse, implementing Texas Standard Electronic Transactions 2.0, improving Load Research and Distributed Load Control applications, and upgrading Corporate Applications and Transaction Systems. ERCOT also identified as "no regrets" projects standard software maintenance and upgrades, which must be undertaken to keep ERCOT systems current, as well as potentially all retail projects, since ERCOT does not now believe that retail systems will be directly affected by the conversion to Texas Nodal. ERCOT noted that because of the overall availability of resources, the market design process may cause delays for some of these projects.

TXU commented that there are some "no regrets" projects that should be undertaken. These include establishing trading hubs, developing a shaped product, developing a day-ahead energy market, adapting ERCOT's deployment of regulation service, modifying the relaxed-balance-schedule capability, and achieving greater market transparency through improvements in data and price availability.

Reliant emphasized three "no regrets" items that should be addressed by ERCOT during the interim: ending the ERCOT-wide uplift of local-congestion cost and implementing a zonal uplift of non-CSC costs; rectifying the inability of ERCOT's systems to execute the ten-minute prior deployment of balancing energy and minimizing the substitution of regulation for balancing-energy service; and eliminating the limitation on transmission congestion rights (TCR) ownership.

Cap Rock and Bryan proposed that more attention should be given to transmission planning, system improvement projects, ERCOT credit issues, and generation-siting issues. Cap Rock and Bryan also argued that market power issues have not been adequately addressed, and recommended that the commission further investigate market power and consider additional protection for Texas consumers. Denton/Garland agreed that transmission planning and market power mitigation were "no regrets" issues.

OPC commented that with or without the implementation of the new market design, problems with market design would persist and that market participants, in conjunction with the commission, would try to find solutions. OPC stated that this type of activity would be required regardless of whether the implementation date is in 2006 or 2007.

AEP stated that taking time to identify "no regret" items and then developing and implementing these measures would only cause further delay. CPA also commented that developing or implementing a "no regrets" list could serve as a distraction from the development and implementation of the Texas nodal market, and suggested that rather than taking interim measures, ERCOT should implement measures that are elements of the Texas nodal design that could be installed prior to the total design to alleviate some of the current problems. Acknowledging that there might be some problems in the interim, CPA recommended that the commission focus on the process of moving toward the proposed Texas nodal design rather than patching the current system.

In reply comments, ARM strongly opposed CPA's statement that there should be no "no regrets" items implemented during the interim, and stressed that the market needed to continue functioning and evolving. ARM specifically pointed to the benefits a day-ahead market would afford REPs even before the new market becomes operational.

In reply comments, Exelon agreed that it was neither feasible nor cost-effective to pursue a formal "no regrets" list, but asserted that ERCOT obviously will have to continue to function well during the design process, and urged full support for the work of ERCOT and the committees to continue to improve the market.

Commission response

The commission agrees with Exelon that it is not necessary to pursue a formal "no regrets" list. As recognized by San Antonio and other parties, the ERCOT committee process can be used to identify and address "no regrets" issues. Through this process, improvements to the market can be continued, while balancing the resources needed to design the new market with the importance of any proposed interim improvements and their costs.

Question 2: The commission has stated its intention to have most of the implementation of this rule take place through the ERCOT stakeholder process. Nevertheless, are there additional issues not addressed by the rule that the commission should address?

Transmission planning

Comments

LCRA stated that while generator interconnection in ERCOT is very efficient, the current rules give the generators and investors a sense that needed transmission will always be built. LCRA asserted that it should be made clear that only transmission found to be in the public interest will be built, thus making the generators assume the risk of a poor plant siting.

Commission response

The commission believes that a Texas nodal model as set forth in §25.501 will lead to a significant departure from current practice in terms of the siting of both generation and transmission resources. In particular, a nodal model is expected to send generators and their investors appropriate signals to identify the costs of transmission congestion in particular locations and to incorporate those costs into siting decisions. Thus, if a generator builds behind an existing transmission constraint, it will assume the risk of that siting decision in the form of nodal energy prices that reflect the scarcity of the transmission system to deliver the generator's power to load. The generator will also have to consider the uncertainty regarding the likelihood and timing of any transmission upgrades.

The commission does not find that it is necessary to make a declaration, as suggested by LCRA, that only transmission facilities found to be in the public interest will be built. The commission certifies the construction of transmission facilities only if the requirements of Texas Utilities Code, Title II (Public Utility Regulatory Act, or PURA) §37.056 are met. Although the statute does not explicitly require certificated facilities to be in the public interest, it does require the commission to consider a broad array of factors related to the public interest, including the need for the proposed transmission facilities and the adequacy of existing service.

Comments

CPA supported continued improvement to the transmission-planning process, so that the planning process is aligned with the Texas nodal market design and implementation in the future, and encouraged the commission to establish a formal process for transmission planning that is open, participatory, and transparent. CPA commented that synchronizing a comprehensive transmission-planning process with the Texas nodal market design would be required to facilitate market decisions by participants and to realize the benefits in the commission's proposed rule, as cited by Dr. Eric Schubert, regarding improvement in siting of generation and transmission and in demand response.

In reply comments, TXU opposed adding additional details on transmission planning, as proposed by CPA, or on hubs and load zones, as proposed by ARM, because it would stifle consensus on a working Texas nodal model.

Commission response

Although the commission agrees with TXU that additional details on transmission planning are not appropriate to include in §25.501, it also agrees with CPA that continued improvement to the transmission-planning process and integration of that process with the nodal model will be important to realizing the benefits of a nodal model. In recent years, ERCOT has made considerable improvements in the transmission-planning process by working to formalize planning guidelines, to increase stakeholder involvement, and to advance its modeling capabilities and other planning tools. The commission will continue to support these efforts, as well as other efforts by ERCOT and market participants to synchronize market design decisions with the transmission-planning process. Moreover, the commission encourages parts of the transmission-planning process to be open to all stakeholders. Such transparency will facilitate communication among ERCOT, the commission, and various market participants and will be important in developing least-cost solutions to transmission constraints in the future. The commission recognizes, however, that parts of the transmission-planning process will necessarily remain confidential to protect commercially sensitive information.

Market information

Comments

CPA stated that the rule also needs to address the provision of market information to participants, while honoring the confidentiality of commercially sensitive information, because such market information is required to facilitate market participants' decisions and to realize the benefits cited by Dr. Schubert, and because lack of market information and price transparency is a major problem in the current market and should be avoided under Texas Nodal. CPA suggested that ERCOT should post in a timely manner on its website such data as day-ahead and real-time prices at all locations (including nodes, zones, and hubs), and a summary of mitigation actions in megawatts per hour (MWhs) mitigated or some other relevant measure.

Commission response

The commission acknowledges that market information is critical to fully realize the benefits of a nodal model. Indeed, price transparency and the availability of other market information are essential to any successful, competitive market. The commission believes that additional improvements can be made to enhance price transparency and to increase the accessibility of data to market participants. Rather than addressing the provision of detailed market information in the rule, however, the commission prefers that such details, including the type of market information to be disclosed by ERCOT and the protection of commercially sensitive information, be addressed, at least initially, by stakeholders as part of the conceptual and detailed design of the nodal model.

Stakeholder process

Comments

Denton/Garland stated that the commission should monitor the stakeholder process to ensure elimination of market-power abuses, and should provide clear expectations to the stakeholders so they avoid spending time and money on a design that would prove unacceptable to the commission, as has happened in the past.

Austin agreed that the rule should be implemented through a stakeholder process, and added that the following should also participate: ERCOT staff, in its double role of supporting stakeholders in the design process and implementing the design; commission staff, as a partner in the design process; and the commission in its role of dispute arbitrator. Austin stated that maintaining the stakeholder process is critical, as only the stakeholders have the commercial know-how to design a functioning market. In addition, it stated, commission staff involvement will elicit new ideas. Austin repeated that the ERCOT staff should support the stakeholders and then implement the design, in keeping with its appropriate role. Austin summarized the successful functioning of the stakeholder process, particularly since 1995, and rejected the view that the stakeholder process should be dropped because of the concerns that it may be slowing the market. Austin asserted that the proposed new plan for market design offered by Mr. Thomas Noel, Chief Executive Officer, ERCOT, should be rejected, because it would limit participation by the stakeholders and result in ERCOT picking winners and losers, thus altering its role as an independent organization. Austin expressed the view that ERCOT's main role is "to make trains run on time," and since several of its important functions are still behind schedule, ERCOT should focus on fixing those and not divert its talent to market design, which should be the job of stakeholders.

Cap Rock and Bryan expressed the view that many stakeholders do not have the time or resources to participate fully in the ERCOT stakeholder process and that the commission should ensure that all participants have an opportunity to provide input. Both suggested that the commission make clear its intentions so that everybody understands the mission of this project. STEC agreed that the design and implementation of the Texas nodal model should take place through the ERCOT stakeholder process, and that it should not be delegated to a committee or a working group, but must be open to all. STEC also stated that the commission should ensure that the new design does not discriminate against a market participant because of size or classification.

CPA urged the commission to require that an oversight committee establish a process that provides for significant input by all stakeholders and is disciplined by mandating certain milestone dates for the process. (In responding to question 1(a), CPA recommended that ERCOT establish a Process Oversight Committee to review proposals concerning the stakeholder process and to develop and propose a process based on this input.) CPA noted that the proposed rule sets an implementation date for Texas Nodal, but does not address the process or set major milestones.

Exelon supported a stakeholder-driven process, with the implementation date set and not delayed by filibusters from opposing parties. Exelon recognized the need for all parties to gain an understanding of nodal systems, and to be able to provide input. Exelon stated that ERCOT should facilitate the process through its technical expertise; quickly assign a project manager; and in the implementation phase, structure a timeline for market software testing to ensure a smooth transition.

ARM reiterated its belief in the stakeholder process as the best way to design the market, although the commission should set firm deadlines for work products. ARM expressed concern about the design plan as proposed by Mr. Noel on June 18, 2003, because it would limit stakeholder participation and change ERCOT from a transactional to a policy-making body, which would be contrary to legislative intent. ARM stated that SB7 charged ERCOT with ensuring the performance of certain operating functions, such as access to the transmission and distribution system, reliability of the network, timely communication of customer-choice information to customers, and accurate accounting of electricity production and delivery, while not having an interest in the market outcome. ARM affirmed the need for ERCOT to participate in the market design, but only in a technical-advisor capacity. ARM suggested that the commission encourage participation of facilitators, publishing of issues well in advance so all could participate, a quick process for moving issues through ERCOT's Technical Advisory Committee (TAC) to avoid bottlenecks, and the use of the commission for contested-issue resolution.

ERCOT asserted that the development of Texas Nodal would be a collaborative process, directed by ERCOT, with the involvement of facilitators, TAC, subcommittees, and any stakeholders for Phase I; for Phase II, the standard ERCOT stakeholder process would be used, with active commission staff participation during all phases.

In reply comments, CPA agreed with Austin, ARM, STEC, and Reliant that the design of Texas Nodal should be a stakeholder-driven process, and shared their concerns about Mr. Noel's proposed plan, including minimizing stakeholder input and ERCOT picking winners and losers. CPA stated that the stakeholder process should include a mechanism for the commission to make timely policy decisions and recommendations, to accommodate new ideas and directions, and to be inclusive. CPA also agreed with ARM and Austin that ERCOT should be primarily a technical advisor, not an ultimate decision-maker, and that the commission should be involved in market design. OPC commented that Mr. Noel's plan would move market design from the stakeholders to ERCOT.

San Antonio, Reliant, TXU, and AEP stated that there are no additional issues. AEP also stated that the rule establishes a clear set of principles for market development.

TXU encouraged the commission to continue using the stakeholder process to design the market; when contested issues arise, they should be taken to the commission for resolution.

Commission response

The commission agrees with the parties' comments that the rule should be implemented through an inclusive, participatory process, and has therefore included language in subsection (m) of the final rule to require ERCOT to use a stakeholder process to develop a wholesale market design that complies with the rule. As Austin pointed out, stakeholders have the technical and commercial expertise to develop the market-design details and to ensure the final work product is cohesive and feasible from a commercial, operational, and financial standpoint. ERCOT should support stakeholders and the commission by facilitating the process, providing technical expertise, and implementing the market design. The commission agrees with ARM that ERCOT should also establish a structured timeline and process for market testing to ensure a smooth transition. In addition, commission staff will continue to have an active role by providing input into the design, monitoring progress and issues during the design and implementation stages, and communicating with the commissioners about progress and issues.

The commission agrees with Cap Rock, Denton/Garland, and others that the commission should set clear expectations, and believes that this rule is a major first step in doing so. The rule provides the general framework and timeline for the development and implementation of a nodal market in ERCOT, but leaves considerable flexibility to stakeholders to address the necessary details. Nevertheless, as discussed below with respect to subsection (d) of question 3, the commission intends to conduct three follow-up rulemakings to address certain key issues for the Texas Nodal, namely issues concerning the day-ahead market, congestion rights, and price protections.

The rule establishes deadlines for two key milestones (i.e., filing of protocols and load zones for approval by the commission and final implementation). The commission does not find it appropriate to prescribe additional deadlines in this rule. The commission will, however, be active in monitoring the process to ensure that progress is being made and to provide feedback. Furthermore, the commission will approve the protocols and initial load zones for the new wholesale market design, and will consequently resolve disputes concerning them.

Given the aggressive deadlines in the proposed rule, the commission understands the rationale behind Mr. Noel's plan, particularly with respect to the process for the initial market design. It would be very difficult to complete the initial market design by January 1, 2004, as initially proposed by the commission, and still provide a fully open and participatory process for addressing many complicated and controversial issues. Therefore, as discussed under question 1 above, the commission has revised the timeline in the rule for filing the proposed protocols and for the implementation of a nodal market in ERCOT. The commission finds that the revised timeline in the final rule will allow for a more inclusive process.

The commission acknowledges Cap Rock's concern regarding the limited time and resources of smaller entities. Publishing issues well in advance (to the extent possible), as suggested by ARM, will be useful to assist entities with planning for, and monitoring, the process.

With regard to STEC's comment regarding avoidance of discrimination based on size or classification, the commission notes that PURA §§39.151(a)(1) and 35.004(e) require that the nodal market design not be unreasonably discriminatory.

The commission reiterates that the ERCOT nodal design process should facilitate the participation of stakeholders, but declines to address in the rule the details of the stakeholder process.

Comments

CPA identified three other issues that needed to be addressed: subsection (d)(2), congestion pricing and allocation of congestion costs; subsection (d)(5), zonal aggregate energy process for load; and subsection (d)(6), transmission rights.

Commission response

CPA's comments are addressed below in connection with subsection (d) of the proposed rule.

Comments

CenterPoint stated there are several issues that need to be addressed. First, subsection (e) of the rule should be clarified because the wording of the requirements for ERCOT to approve market redesign by July 1, 2004, to present a cost-benefit analysis, and to implement the new market design by March 1, 2006, suggests that Texas Nodal will be implemented even when benefits are smaller than the costs. Second, CenterPoint emphasized the importance of freezing the redesigned protocols before moving to implementation, in order to facilitate implementation of the new system. Third, if staff believes that congestion costs must be shifted from loads to resources, subsection (d)(2) should be clarified by adding the word "*feasibly* relieve congestion."

Commission response

CenterPoint's first suggestion is addressed under question 5, below, related to the cost-benefit analysis.

With regard to CenterPoint's second suggestion, the commission believes that it is appropriate to first complete the protocol development, review, and approval processes before moving forward with full implementation of the nodal market (i.e., software development, integration, and testing). This sequence will not only provide market participants and ERCOT greater certainty when planning and developing their systems, but will also likely avoid implementation problems. Although the commission recognizes that some aspects of implementation may have to begin before the final approval of the protocols, it does not contemplate that market participants will be developing the protocols at the same time that they are developing the systems to implement the protocols, as was done with the initial ERCOT market design and implementation following the 1999 amendments to PURA.

CenterPoint's third suggestion is addressed below in connection with subsection (d)(2) of the proposed rule.

Question 3: On what timeline should the following issues be addressed?

(a) Congestion rights

(b) Zonal boundaries for settling load imbalance charges

(c) Day-ahead market/power exchange

(d) Market mitigation

Comments

ERCOT recommended concurrent development of all of these and other major market components during the market-design process. It stated that while plans to implement the new protocols are being made, it can be determined whether a phased implementation of particular components is appropriate. Nevertheless, ERCOT expressed the strong belief that a day-ahead/forward market should be implemented early.

TIEC opined that no market-design proposal can be evaluated until congestion rights and market mitigation are addressed. In its view, congestion rights will color every other debate; moreover, evaluating the market will be impossible if loads are not allowed to manage their congestion risk. Similarly, it stated, because nodal systems are often considered more vulnerable to gaming, an understanding of how the market will be managed and policed will be necessary for participants to evaluate possible market structures.

Oxy agreed with TIEC that early resolution of congestion rights and market mitigation is critical to developing a workable market design and ensuring an efficient design process. In fact, Oxy advocated addressing these two topics first in the process. Oxy noted that congestion rights provide the only means to even partially hedge against congestion under a nodal system, so that load-serving entities (LSEs), non-opt-in entities (NOIEs), and consumers must understand how and to whom congestion rights will be allocated in order to determine the impact of a new market design and how they will manage their own exposure to congestion costs. Oxy additionally stated that nodally priced systems are much more susceptible to gaming than are other systems, because all nodes are interrelated and manipulation at one node can have significant effects throughout the system. (In reply comments, CPA disputed the contention that market manipulation is greater in nodal systems.) Consequently, Oxy concluded, stakeholders need early assurance that the new Texas nodal market will incorporate workable safeguards to limit opportunities to artificially raise prices by gaming, market manipulation, or the exercise of market power.

OPC opined that market mitigation must occur simultaneously with the development of any component for which it is required.

TXU acknowledged that these four issues are important, but opined that they should be addressed after first establishing an operational model for ERCOT, *i.e.*, what indicators it will monitor and what actions it will take in response to their variations. A settlement system then must be developed that will be consistent with this operational model. After designing the ERCOT operational model and the settlement system, TXU opined, the four specified issues can be considered as desired.

AEP stated that these issues, as well as the associated timeline, should be addressed as the overall market is being designed. AEP suggested that these topics should be resolved as part of the ERCOT stakeholder process, as the proposed rule had already provided sufficient guidance to stakeholders to facilitate discussion.

LCRA asserted that these issues should be addressed on the same timeline in the market-design process, so that market participants would have a complete picture of the future market structure. LCRA noted that the ZEN model incorporates all four matters to some degree.

San Antonio commented that all of these issues should be addressed on the same timeline and via the same process that will be used for the design and protocol development for all other issues relating to implementing the proposed rule. Austin stated that these issues must be addressed both in designing the market and in developing the protocols. It further suggested that the timeline for addressing each issue be determined early in the process and planning phase of market design.

STEC recommended dealing with all four issues as early as possible, as they all are connected to the development of a new market design. Considering the availability of the resources of commission staff and smaller stakeholders, and commission staff's stated intention to hold more workshops on the day-ahead market/power exchange topic, however, STEC recommended addressing these issues in the following order: congestion rights, zonal boundaries for settling load-imbalance charges, market mitigation, and day-ahead markets and power exchanges.

Bryan recommended addressing early in the process the topics of congestion rights and zonal boundaries for settling load-imbalance charges. Regarding the former, Bryan asserted that preassigned congestion rights (PCRs) available to NOIEs with existing contracts to serve their native loads must be protected in any new market design. Noting that many bilateral contracts are for multi-year terms, Bryan opined that a continual process of changing zones or creating new ones will complicate and impede the development of new wholesale power supply contracts.

On the other hand, Bryan suggested addressing the question of a day-ahead market or power exchange only after decisions are made on market design. Bryan further maintained that a day-ahead market or power exchange should be established only if a cost-benefit analysis proves that there is sufficient market support and need to justify the expense.

Believing that market-power issues have not been adequately addressed in ERCOT, Bryan urged the commission to continue to pursue changes and additions to the automatic mitigation procedures (AMPs) with the current market design. To deal with future market mitigation, Bryan suggested that the commission consider establishing a market-monitoring function that would be independent of stakeholders and whose sole function would be to implement market-mitigation plans and otherwise deal with market-power issues.

Like Bryan, Denton/Garland advocated addressing early in the process the key issues of congestion rights and zonal boundaries for settling load-imbalance charges. Denton/Garland agreed with Bryan that PCRs now available for NOIEs must be preserved. Denton/Garland further observed that the issue of whether transmission congestion rights (TCRs) should be initially allocated or auctioned will be controversial and should be decided early. As for the zonal-boundary issue, Denton/Garland again stressed that uncertainty is a major concern. Early consideration should therefore be given, Denton/Garland stated, to such issues as the total number of zones, how zonal boundaries will be set, and how often and under what circumstances they will be changed.

Denton/Garland opined that a day-ahead market should be designed after the protocols are written to implement the final market design, because the design of a day-ahead market or power exchange is very dependent on the final market design, but not vice versa. Denton/Garland also recommended taking the time to develop a sound market design rather than hastily implementing a design that requires mitigation after it is implemented. In the meantime, Denton/Garland urged the commission to continue to develop AMPs to prevent market abuses under the current market design.

Reliant stated that the day-ahead market/power exchange is not a requirement of a nodal system, but must be consistent with it. Reliant asserted that the other three items must be fully resolved by the time the nodal market design is implemented.

ARM claimed that firm hubs and zonal boundaries for settling load-imbalance charges must be established before other aspects of market design are dealt with. Pronouncing zonal boundaries to be the biggest unknown variable relating to potential congestion exposure, ARM stated that establishing firm zonal boundaries is the best action the commission can take to promote forward contracting. Turning to the substance of the policy, ARM advocated enhancing liquidity by creating no more than three hubs and three zones. Such a small number will provide price certainty and transparency, it claimed. In addition, ARM expressed the view that a nodal market will not necessitate the periodic redesignation of zonal boundaries. Accordingly, it stated, commission rules should severely limit boundary changes, thereby fostering market stability and liquidity.

CenterPoint suggested determining congestion rights and zonal boundaries for settling load-imbalance charges at the beginning of the proposed market. Doing so would be critical to providing stability to the new market, it asserted. CenterPoint stated that the other two issues probably could be addressed on a slower timeline.

CPA emphasized the importance of developing clear and robust market-power-mitigation procedures and establishing the type and allocation of congestion rights. The former would help to ensure confidence in the market, and the latter would directly bear on participants' exposure to congestion cost, CPA stated. Nevertheless, CPA did not recommend developing detailed rules addressing these two topics immediately. Instead, it proposed that stakeholders address at the conceptual level options for all four of the identified issues, laying the groundwork for commission decisions or direction where needed. In the first phase of market-rules development, CPA suggested devising the detailed rules for the day-ahead market and zonal pricing boundaries. This work would also address rules for phasing in the simultaneous optimization of ancillary capacity services, it noted. After these rules begin to be developed, CPA continued, work should begin to develop rules addressing market-power mitigation and the allocation of congestion rights, and continue in parallel with the development of rules for other aspects of the nodal market. CPA added that the foregoing is really only a proposed staggered starting sequence; it also proposed a more complete timeline, based on its experience in the development of other markets.

Cap Rock affirmed the importance of congestion rights and recommended that any decision relating to them be part of any early decision by the commission or stakeholders. Observing that its wholesale-power contracts are multi-year, Cap Rock commented that continually creating new zones and changing zones alters delivery costs and hence complicates the development of new wholesale contracts. Accordingly, Cap Rock expressed its concern about the structure of zones, especially with respect to their number and duration, and advocated addressing this issue early in the process. Cap Rock did not state a position on when to address the issue of a day-ahead market or power exchange; it did, however, suggest focusing on whether there are sufficient volume and transaction revenues to support the market cost. If a day-ahead market or power exchange is created and requires supplemental funding, Cap Rock stated, power-generating companies should bear the costs.

Like Bryan, Cap Rock urged the commission to continue to pursue changes and additions to the AMPs to deal with market power under the current market design. Also like Bryan, Cap Rock suggested that the commission consider dealing with future market-power mitigation by establishing a market-monitoring function that would be operated independently of stakeholders and whose sole function would be to implement market-power-mitigation plans and otherwise deal with market-power issues.

In reply comments, Exelon disagreed with ERCOT's comments on day-ahead markets, and stated that putting a forward market in place before the real-time market is working reverses the proper timing. Rather, it maintained that the first priority is to establish a workable real-time market, with a day-ahead unit-commitment process, workable market-monitoring and market-power-mitigation protocols, and workable financial rights. Day-ahead markets could be phased in later. As for congestion rights, Exelon advocated an initial allocation for all market participants to preserve stability, with a gradual conversion to auctions. A voluntary auction for residual financial trading rights, it stated, would allow market participants to develop comfort with the auctioning process.

CPA also took issue with what it termed ERCOT's apparent desire to design a forward market before designing and implementing a spot energy market, which would include both real-time and day-ahead markets. CPA's reply comments on this issue are summarized in the discussion of question 4, below.

Commission response

New §25.501 constitutes a decision by the commission to address basic market-design policy issues up-front and was spawned by an issue raised by the commission in *Petition of the Electric Reliability Council Of Texas (ERCOT) for Approval of the ERCOT Protocols*, Docket Number 23220: the uplifting of local congestion costs. This issue coalesced with others, such as the lack of liquidity and the need for a day-ahead market, into the proposed rule. The rule constitutes a major step in implementing an improved wholesale-market design for ERCOT that is consistent with established microeconomic principles. Nevertheless, the commission recognizes that there are other key, wholesale-market-design policy issues that it should address up-front as a follow-up to the current rulemaking. These issues include day-ahead market, congestion rights, and price protections. The commission plans to address issues related to the day-ahead market by the fourth quarter of 2003, congestion rights by the first quarter of 2004, and price protections by second quarter of 2004. The revised timeline in the rule, as discussed above in connection with question 1, will allow for the commission's decisions on these issues to be incorporated into ERCOT's design and protocol development phases.

The commission recognizes that the determination of the zones for settling load imbalance charges will have major commercial and public-policy implications.

However, because numerous factual matters may affect the proper determination of the zones, the commission intends to have stakeholders address this issue as part of the market-design process. In addition, stakeholders should address the necessity of a transition, to be in effect before implementation of the initial load zones required by the rule, to segue from the current ERCOT-wide uplift to load serving entities of local congestion costs to one of direct assignment. An analysis of the prudence and timing of such a transition process should take into account ERCOT's evaluation of needed zones on an annual basis. The commission intends to closely monitor these issues during the market-design process. Furthermore, under subsection (m) of the final rule, the commission has made clear that ERCOT must obtain commission approval for the initial load zones for Texas Nodal.

Question 4: The proposed rule requires ERCOT to implement a day-ahead energy market. One option for such a market is an ERCOT-operated voluntary (but financially binding) day-ahead market based on security-constrained, least-cost dispatch. Such a market would require that all bilateral transactions become financially binding at the resource level in the day-ahead period. Alternatively, a day-ahead market can take the form of a third-party-operated voluntary power exchange, as is used in the United Kingdom and NordPool markets. Power exchanges would permit trading at a limited number of trading hubs, with possible hedging of real-time congestion rents, but could also provide a wider variety of contracts (e.g., forwards, futures, options) and products (e.g., electricity, natural gas) than an ERCOT-operated day-ahead market of the type seen in the northeastern United States. A power

exchange could increase liquidity and price discovery in the bilateral market without requiring submission of financially binding schedules in a day-ahead energy market run by ERCOT. Bilateral transactions not traded through the exchange could become financially binding at the time of congestion settlement, which could take place close to real time.

(a) Would a third-party operated power exchange meet the needs for liquidity and price discovery in the ERCOT wholesale market?

(b) Would incorporating such an energy market into the market design be preferable to relying on a voluntary but financially binding day-ahead energy market based on security-constrained, least cost dispatch?

Comments

CPA and Exelon supported a voluntary but financially binding day-ahead market operated by ERCOT and based on bid-based, security-constrained, economic dispatch in order to create a robust spot market. CPA stated that from this market, a long-term forward market will naturally evolve on its own. CPA opined that ERCOT first needs a robust energy spot market that includes both a day-ahead energy market and a real-time energy market. Once a robust spot market is established, CPA continued, whether such a third-party exchange could meet the needs for liquidity and price discovery depends on the power exchange's forward-market design and the level of participation in the market. It contended that incorporating the day-ahead energy market into Texas Nodal and having

ERCOT administer the market using the same tools and models will align the pricing results of the day-ahead market with real-time nodal prices for generation and zonal prices for load. CPA concluded that this market design will provide transparency between the day-ahead prices and real-time prices and avoid over-scheduling games, while providing an opportunity for small participants to compete and for demand to discipline prices. Exelon recommended that following the implementation of a real-time market under a nodal congestion-management model, a mandatory day-ahead market and capacity-adequacy mechanism be implemented by a date certain.

ARM favored a security-constrained day-ahead market because it provides retailers the ability to lock-in congestion costs whereas power exchanges do not. (ARM asserted that risk is currently borne more effectively by resources than by load, which bears congestion risk despite having limited ability and information to influence the level or price of congestion; hence the need to lock in congestion costs.) ARM commented that liquidity and price transparency are the main benefits of a day-ahead market. ARM maintained that a transparent day-ahead market will benefit REPs that do not have relationships with affiliated generation and must depend on third parties to supply power to their customers. Further, ARM argued, price information made available through a day-ahead market can send price signals that will mitigate the need for a resource-adequacy mechanism, enhance the creation of products, and become an effective pricing index and tool for REPs and the commission.

ERCOT agreed that a financially binding market that relies on resource offers and demand bids to feed a least-cost-dispatch algorithm would probably provide ERCOT with additional information useful for reliability purposes above what ERCOT receives in the current day-ahead scheduling process. However, ERCOT cautioned, this information comes at a cost. CPA disagreed that a third party should provide this service, because it will likely require a duplication of resources and because the only other wholesale energy market that has had a day-ahead energy market (California) had lawsuits resulting in the third party being liable.

ERCOT proposed to operate a forward-market clearing mechanism in partnership with a third-party credit-management and financial-settlement institution. CPA and Exelon argued that if ERCOT's proposal is to design the forward market before implementing a spot-market that includes both a real-time and a day-ahead market, then the approach is backwards. CPA encouraged ERCOT to focus on its core competencies rather than proposing to run a forward market in competition with private companies. AEP voiced the belief that an ERCOT-operated day-ahead energy market would have value that can not be achieved by an exchange operated by a third party, although neither will operate to their fullest potential until after the problems with the real-time market/operations are resolved.

LCRA argued that a day-ahead market based on a fictitious security-constrained, least-cost dispatch is not voluntary, because congestion based on scheduled load and resources is resolved based on forecasted system conditions and day-ahead resource offers. Since congestion rents are charged and transmission rights paid on this fictitious day-ahead market, all qualified scheduling entities (QSEs) must participate in this market to hedge congestion risk. Due to the nature of this market, LCRA asserted, it can easily be manipulated. CPA disagreed and stated that through the day-ahead scheduling and bidding process entities may choose to self-supply and not be exposed to the results of the market, similar to the day-ahead scheduling process used today in ERCOT wholesale market.

CenterPoint generally supported a day-ahead energy market, whether it is a power exchange or an ERCOT-administered security-constrained design; however, it averred, the commission should refrain from mandating any type of third-party-operated power exchange.

LCRA advocated a third-party-operated power exchange as the preferred implementation of day-ahead and forward markets. LCRA commented that a third-party-operated power exchange would not only meet the needs for liquidity and price discovery in the ERCOT wholesale market, but also foster forward markets months into the future.

STEC stated that a third-party exchange would better meet the needs for liquidity and price discovery than the ERCOT voluntary day-ahead market. STEC commented that an ERCOT-run market out of necessity would be a bare-bones market, and broader participation would occur in a third-party exchange.

ERCOT commented that implementation of a third-party exchange is possible under the current Protocols for any entity that can obtain a QSE designation. ERCOT did not anticipate that a third-party exchange would provide significantly better information for ERCOT's evaluation of reliability than is already available in the current day-ahead scheduling process.

Cap Rock suggested that it is questionable whether there will be sufficient transaction volumes to support a third-party power exchange (PX). Cap Rock stated that it has no interest in providing funding to create an independent PX or day-ahead market without assurance that it would save Cap Rock money by reducing power costs or delivery costs.

OPC commented that whether a third-party-operated power exchange could meet the needs for liquidity and price discovery in ERCOT was unclear; it would depend on the nature of the third party running the exchange, the number of participants in the exchange, and the transparency and accuracy of the information posted on the exchange.

Bryan stated that a day-ahead market should not be created without a cost-benefit analysis proving that there is sufficient market support and need to justify the expense. Bryan commented that if a new market, such as a day-ahead market, is necessary, then those that participate in the day-ahead market should be able to support the cost of establishing and operating such a market. Bryan suggested that power generating companies (PGCs) could be charged the cost of creating and managing the market or exchange so that LSEs avoid having to bear those costs.

Bryan and Cap Rock stated that LSEs should not be the default funding sources for market design changes since the retail customer is then the ultimate funding source.

CenterPoint commented that the costs of the market platform should be borne by its users. CenterPoint cautioned that the commission should refrain from mandating any type of third-party-operated power exchange, because if market forces had deemed a power exchange cost-effective, profitable, and/or worthy of development, then a third party would have already implemented one, or would be in the process of doing so.

Oxy, AEP, TXU Energy, Cap Rock, and Austin commented that it is unnecessary to prescribe a detailed day-ahead market at this time. Oxy stated that a day-ahead market can be addressed after decisions are made on threshold issues (congestion rights and market mitigation). AEP noted that incorporating a decision into this rulemaking on the most appropriate path at this time would be premature and would likely lead to unnecessary restrictions in the outcome of the design process. AEP stated that a decision on whether ERCOT should operate a day-ahead market based on a security-constrained or an unconstrained dispatch should be decided as part of the stakeholder process of the development of the Texas nodal market design.

TXU, Austin, and San Antonio advocated allowing ERCOT market participants to address the issue of the day-ahead market design. TXU stated that the basic nodal framework must be designed before a compatible day-ahead market can be fully explored. San Antonio stated that the rule as proposed provides sufficient guidance with respect to a day-ahead energy market and that no additional specificity on this item is required in the rule.

Cap Rock requested that the commission and other stakeholders take more time to educate and study the value of new markets designs and their impacts on stakeholders.

Reliant noted that any of the models may increase liquidity and price transparency in theory, but none will increase liquidity until the industry's credit situation improves.

Commission response

As explained above with respect to question 3, the commission intends to conduct a follow-up rulemaking to address the day-ahead market in more detail. The commission plans to address the concern of Cap Rock that the commission should take more time for education and studying the value of a new day-ahead energy market in Project Number 27678, *Forward Market Structure for the ERCOT Market*.

As suggested in the comments of ARM, CPA, and Reliant, a day-ahead energy market will improve market liquidity, promote greater price transparency, and increase demand-side responsiveness to the ERCOT wholesale market, all of which have the potential to lower electricity prices to all end-use customers in ERCOT.

The current market provides mechanisms for prices to influence power generation companies' development plans and for projected capacity levels to affect forward prices. Commercial and industrial customers typically contract for power for terms of a year or more, and the prices they obtain from REPs reflect the REPs' views of future wholesale prices, based on their efforts to contract for power for future periods. Thus, bilateral contracts at the wholesale and retail levels provide a mechanism for customers to adjust their consumption plans, in response to prices, and for power generation companies to adjust their development plans, in response to prices. Nevertheless, a day-ahead energy market should foster standardized forward power products that are readily tradable, resulting in a more accurate and efficient means for customers and developers to assess future prices and demand. The current means for assessing future prices and demand are not transparent and may not be very effective. Some experts and various market participants have said that until a wholesale electricity market has liquid forward markets for delivery of energy two or three years in the future, a wholesale electricity market will need to have a mechanism to ensure adequate planning reserves. Consequently, the commission will continue to conduct the planning reserve rulemaking, *Rulemaking Concerning Planning Reserve Margin Requirements*, Project Number 24255.

Question 5: When ERCOT files the Protocols to implement the rule, should it also file a cost-benefit analysis that supports the manner in which ERCOT chose to implement the rule, including evaluation of major options?

Comments

ERCOT, Denton/Garland, Reliant, STEC, ARM, Bryan, Cap Rock, TXU, CenterPoint, OPC, LCRA, Austin, and San Antonio generally supported a cost-benefit analysis, but disagreed on the appropriate time to conduct one and the nature of such an analysis.

ERCOT committed to developing a cost-benefit analysis, concurrently with protocol development, during Phase II of the market design process. ERCOT indicated that developing the market rules and then attempting to quantify the potential costs and benefits will help to provide a sound basis for decision making. In addition, OPC noted that a cost-benefit analysis would garner support for the particular design created by ERCOT and may identify and correct problems such that the resulting design is best for the market.

Reliant, TXU, CenterPoint, and OPC suggested that ERCOT file a cost-benefit analysis when it files the protocols to implement the rule. Reliant and TXU recommended comparing the costs and benefits of the proposed protocols with the costs and benefits of the existing market structure.

CPA disagreed with TXU that a cost-benefit analysis of a nodal system as compared to the current ERCOT zonal system should be performed after the market has been designed and the protocols have been written. CPA argued that TXU misinterpreted this question and that the commission is not requesting such a full-blown analysis.

CenterPoint proposed that the commission staff and the commission, as well as ERCOT, file all supporting information on changes from a zonal to a nodal market design. CenterPoint asserted that the proposed rule presupposes that the cost-benefit analysis is going to prove that the new nodal model is warranted. According to CenterPoint, the commission is creating a perception that the new market design will be implemented, even if the expected benefits are less than the potential costs.

LCRA argued that it is imperative that ERCOT file cost analyses for not only the manner in which ERCOT chooses to implement the rule, but also other major options. STEC also suggested that the analysis show the costs and benefits of one option over another. LCRA indicated that it may be difficult to quantify the benefits and that it may be reasonable to accept the benefits of going to a nodal model and performing cost comparisons on different ways to achieve the design. LCRA asserted that ZEN is the least-cost version of a market design complying with the rule and should be adopted.

Denton/Garland, Bryan, Cap Rock, and Austin recommended performing a cost-benefit analysis before the decision to move to a nodal model is made. They suggested that ERCOT file protocols after a decision on the appropriate market design is made using cost-benefit studies and other detailed analysis. Denton/Garland and Cap Rock urged that time be taken in this rulemaking process to develop and evaluate alternative solutions and to choose the most cost-effective solution based on a balanced cost-benefit analysis. Cap Rock emphasized that it appears that implementation of market-design changes are already moving forward at a "worryingly" rapid pace without any appropriate or thoughtful study or consideration of alternatives. Cap Rock expressed concern about the potential to spend millions of dollars of public funds and not address such issues as market power, increased efficiency and use of both transmission and generation resources, and adequate market signals to resolve congestion. Further, Cap Rock requested that the commission assure consumers that the costs of the proposed rule are justified and that any allocation of costs to individual stakeholders is fair, equitable, and reasonable to all. According to Cap Rock, there has not been sufficient proof that the current market design proposals are economically justified for its customers. Finally, Cap Rock recommended that the costs associated with any new market design be assigned to those parties that will be participating in those markets. For example, Cap Rock suggested that the cost of a day-ahead market be funded by those generators that are participating in the market.

ARM also recommended performing a cost-benefit analysis, so that the value of moving to a nodal system is determined before the move actually occurs. According to ARM, such analysis must encompass all potential implementation costs, including the costs associated with system design and implementation problems.

Austin suggested that, if the commission intends to move forward with this rule without first conducting a cost-benefit analysis, it should delete the rule requirement for a cost-benefit analysis. Austin argued that an after-the-fact cost-benefit assessment does not serve any significant policy purpose, would waste resources, and would distract ERCOT staff from its primary task of implementing new systems.

San Antonio interpreted this question to mean, "should ERCOT file a cost-benefit analysis that supports its particular implementation of a nodal market design consistent with the requirements of the rule?" (CPA supported this interpretation.) According to San Antonio, this type of analysis is in contrast to the question of whether ERCOT should move from a zonal-based to a nodal-based market structure. Like Austin, San Antonio advocated that additional costs, time, and resources should not be spend on a formal cost-benefit analysis if the analysis is intended merely to justify which "flavor" of nodal design ERCOT finally proposes in the protocols. The costs of such an exercise to distinguish between multiple, close shades of grey would outweigh the benefits, according to San Antonio. San Antonio supported, however, a rigorous cost-benefit analysis upon completion of detailed design elements that would inform the decision on whether to remain with the commitment in the rule to overhaul ERCOT's fundamental market design.

In reply comments, Exelon and CPA agreed with Austin and San Antonio that a formal, after-the-fact study is not needed. CPA and Exelon argued that there is sufficient evidence in the record and provided by comments for the commission to decide now to move forward with implementing a Texas nodal model. Exelon suggested, however, that a description of costs and benefits of the individual elements of the market design (or designs) submitted for approval would be helpful to the commission. CPA advocated performing an on-going assessment as the nodal market design is being developed to ensure that particular features are designed and implemented to provide a positive net benefit. According to CPA, this assessment should document the pros and cons of various design details and why particular alternatives are chosen, such as single-part bids versus multi-part bids and directly allocating financial transmission rights (FTRs) versus allocating the auction revenue rights from FTR auctions. CPA noted that such an assessment would provide timely feedback, would ensure that proposed features will not diminish the value of the existing retail market design, and would result in a better overall market design.

Like San Antonio, AEP was uncertain as to the intent of this preamble question. If the question is whether a cost-benefit analysis should be conducted of transitioning from the current system to the market structure that ERCOT chooses to implement the rule, then AEP is not opposed to such an analysis. AEP indicated, however, that the commission should be mindful that many of the benefits, including liquidity, transparency, and reliability, may be difficult to quantify. AEP stressed that any cost-benefit analysis must account for reliability risks linked to the current market structure. If the question is whether each individual design should include a cost-benefit analysis to support the decision (e.g., transmission rights versus obligations, scheduling deadlines, mandatory versus voluntary bidding), AEP indicated that although such factors should be considered as decisions are made, filing a detailed cost-benefit analysis for every decision might prove unnecessarily burdensome, depending on the level of documentation required by the commission. If the commission prefers this type of analysis, AEP recommended that the commission clarify how ERCOT should determine when a decision requires cost-benefit analysis and the level of detail that will be required.

Commission response

As to the question of whether the cost-benefit analysis required by the rule requires a comparison of ERCOT's preferred design to comply with the rule to the current market design, the answer is yes, and subsection (m) of the final rule makes that clear. However, as discussed in the commission's cost-benefit analysis in the preamble for the proposed rule, the discussion below of the commission's cost-benefit analysis, and in other parts of this order and other filings in this proceeding, the status quo market design is unacceptable, because it is inefficient and is unsustainable in the long run. Although a number of parties expressed concern about the cost of the new market design required by the rule, they failed to acknowledge the substantial costs of continued use of the current market design. The commission identified a major flaw in the market design two years ago in the docket approving the original protocols — the lack of direct assignment of congestion rents for local congestion — and this flaw has still not been corrected. ERCOT's inability to correct this flaw through the stakeholder process gave rise to this rulemaking. Furthermore, additional, major flaws in the current design have also been identified, especially the lack of resource-specific bid curves for use in dispatch by ERCOT, the lack of a day-ahead market, and the lack of stable zones. In addition, as explained below with respect to the commission's cost-benefit analysis, experience continues to confirm the inability of the current market design to timely respond to changed operating circumstances. It is necessary for the commission to exercise leadership by enacting this rule, in order to ensure that the major flaws in the current market design are corrected. Therefore, the commission has amended the rule to make clear that the cost-benefit analysis shall evaluate only options that meet the requirements of the rule. However, as discussed below concerning proposed subsection (d)(2), there are potentially a number of major options to implement the rule.

As to Cap Rock's concern that issues such as market power, increased efficiency and use of both transmission and generation resources, and adequate market signals to resolve congestion, be addressed, a review of the rule and the preamble discussions of the proposed and final rules clearly shows that these issues are central reasons for the rule and in fact are addressed by the rule.

The commission agrees with CPA that comparing costs and benefits of various options should be an ongoing part of the stakeholder conceptual and detailed design process. The commission, however, also agrees with ERCOT's suggestion that a more formal cost-benefit analysis be conducted concurrently with protocol development. This formal cost-benefit analysis will be filed as part of ERCOT's application for approval of the protocols to implement the rule. This cost-benefit analysis will help assure the commission and stakeholders that the market design protocols ultimately approved by the commission will constitute a cost-effective means to implementing the rule. As part of the cost-benefit analysis, the commission expects ERCOT to evaluate the extent to which existing systems can be modified to meet the requirements of the rule, compared to replacing existing systems with new ones. Although ERCOT must fully evaluate the costs of various approaches to complying with the rule, the goal, however, is not solely minimization of implementation costs. Instead, ERCOT and its stakeholders must balance the cost of different approaches with the relative benefits of different approaches.

Comments

STEC, TXU, Cap Rock, Bryan, and Denton/Garland stressed the importance of having an independent third party perform a cost-benefit analysis on the manner in which ERCOT chooses to implement the rule. TXU proposed that ERCOT and the ERCOT market participants employ such a third party.

Commission response

The commission agrees with STEC, TXU, and other parties that it is important for the cost-benefit analysis to be conducted by an independent third-party, and the commission has amended the rule to make independence a requirement for the analysis. The commission contemplates that ERCOT staff will assist the third-party entity that conducts the analysis and facilitate the process by providing data and technical and operational information. In addition, the commission finds that the analysis should be paid for by ERCOT through its budget. It is important, however, to maintain the independence of the third party throughout the process. Although some stakeholders, and even the commission, may not agree with the third party's conclusions, the third party's analysis should nevertheless be a very helpful tool to analyze the costs and benefits of various market design options in the commission's protocol approval docket.

Comments

STEC, Magic Valley, Mid-Tex, Rayburn, and Denton/Garland recommended that any cost-benefit analysis associated with this rule include a cost impact analysis of Texas Nodal on various regions and market segments, including their ability to stay economically competitive in the future.

Commission response

Although the commission has determined that the net benefit of implementing this rule is positive and significant, the commission agrees that the benefits and costs of Texas Nodal will vary among regions and market segments. Consequently, the commission expects ERCOT to have included in the independent cost-benefit analysis required by subsection (m) of the final rule, an analysis of benefits and costs on a region by region and market segment by segment basis.

Additional Comments on commission's Cost-Benefit Analysis in Proposal for Publication

Comments

Numerous parties commented on the commission's cost-benefit analysis in the preamble to the proposed rule.

Based on the commission's base-case net present value of costs and benefits presented in the preamble (i.e., $189 million), San Antonio estimated that the levelized net benefit would be approximately 7.0 cents per MWh (in 2006 dollars ($2006)) over the ten-year period. San Antonio observed, however, that given the speculative nature of the assumptions in the commission's analysis, it is not difficult to envision a scenario in which the expected net benefit of $189 million could become negative, especially given that this best-case net benefit is highly leveraged against over $150 billion in wholesale market sales over the same time period. For example, San Antonio estimated that a mere 0.18% increase in wholesale power prices ($2006) over the ten-year period would totally erode even the best-case net present benefit in the commission's analysis. While this may not be the expected case, it is certainly well within the range of potential outcomes, according to San Antonio. In addition, San Antonio argued that even if the best-case estimate of savings was known with certainty, it is certain that these benefits will not accrue evenly across the electric-customer base in ERCOT. Nonetheless, San Antonio projected that there are likely to exist long-term benefits to its customers from the market changes envisioned in the proposed rule (to the extent that details are properly implemented through the stakeholder process and finally approved in the protocols, the costs and transition timeline are properly controlled to produce a least-cost transition, and certain changes are included in the final rule).

San Antonio opined that any cost-benefit analysis at this point is a high-level review, subject to multiple and speculative assumptions, and can only yield a determination that it is likely that the benefits may exceed the costs, or vice versa. San Antonio pointed out that the time and effort required to state with certainty that the benefits of implementing the proposed rule outweigh the costs are substantial. According to San Antonio, no person has devoted the time and effort to reach such a conclusion at this time. Further, San Antonio questioned the ability to accurately predict the long-term costs and benefits prior to having developed the details of the high-level framework presented in the proposed rule.

STEC recognized that the implementation of a nodal system can produce some benefits, such as a better organizational structure for making trades and minimizing the cost of generation redispatch to mitigate local congestion. STEC indicated, however, that much of the commission's cost-benefit analysis is, at best, based on speculation. STEC argued that the ten-year estimate of costs and benefits should be disregarded, noting that no one can forecast with any accuracy what the electric industry will even look like in ten years.

Magic Valley, Mid-Tex, and Rayburn urged the commission to consider ERCOT's suggestion to view with caution the benefits presented in the preamble, particularly those benefits relating to reduced congestion costs and factors and incentives for locating generation near load. They indicated that it is not apparent that the cost-benefit assumptions relied upon by the commission are well founded. They acknowledged that nodal pricing may benefit some customers and that it is highly probable that one or more of their cooperatives (coops) could benefit, given the geographic diversity of the coops and the loads that they serve. Nonetheless, they stated that nodal pricing should not be adopted unless it is absolutely clear that it is necessary to ensure sound energy policy in ERCOT, and noted that the commission should consider more than just economic efficiency.

Finally, Magic Valley, Mid-Tex, and Rayburn urged the commission to seriously weigh the costs and benefits of a transition to a nodal system, rather than simply assuming that benefits will outweigh costs because some economists say so. At a minimum, they proposed that the commission first model the economic consequences of a nodal system before implementation. OPC supported this modeling proposal, noting that the significant equity issues at stake beg the need for modeling the effects of a nodal system.

Commission response

The commission concurs with San Antonio that there is a range of possible outcomes. For instance, the net benefits of going to Texas Nodal may be even higher than stated in the preamble to the proposed rule. In fact, as explained further below, the commission believes that the net benefits will likely be greater than the conservative estimate in the preamble to the proposed rule. San Antonio, Magic Valley, Mid-Tex, and Rayburn, OPC, and STEC expressed concerns about how the projected benefits discussed in the preamble, if real, will be distributed among market participants. The commission has commented on the distribution of these benefits elsewhere, specifically how the size and configuration of load zones will ease, if not eliminate, the impact of the Texas nodal model on customers.

The commission finds that the need for the Texas nodal market design is compelling on two grounds: (1) to address the recurring problems and economic inefficiencies that have resulted from the lack of direct assignment of local congestion rents and lack of resource-specific bid curves, and (2) to make the ERCOT wholesale market more robust and flexible in the face of changing market conditions and technological advances in resources. In the preamble to the proposed rule, the commission provided a quantitative analysis that shows that the net benefit from moving to Texas Nodal on the basis of economic efficiency alone is significantly greater than zero. Just as important, however, are other benefits that the Texas nodal model provides that are not easily quantified. An important benefit of a Texas nodal market design that was not quantified in the preamble to the proposed rule is its superior flexibility, which will make the ERCOT wholesale market design sustainable for the long term and foster a wider diversity of services for retail customers in the coming decade.

The ERCOT wholesale market has seen a number of expensive problems arise in the past two years resulting from the lack of direct assignment of local congestion rents: the wind rush that left 755 megawatts (MW) of wind farms behind a 400 MW transmission constraint near McCamey, Texas, increasing levels of OOME Down payments; the owners of new thermal generating plants not facing the consequences of building their plants at sites that create new pockets of local congestion; the lack of transparency of real-time dispatch; and the uplift of local congestion costs associated with a new North to Houston constraint resulting from the South Texas Project being out of service this summer.

Some of these problems required time-consuming intervention, because the automatic mechanism that would have addressed these contingencies — direct assignment of local congestion rents — was not in place. The current wholesale market system relies too much on intervention by ERCOT stakeholders who have vested financial interests, which slows down or even prevents the problems from being addressed in a prompt manner. The lengthy debate on whether to directly assign congestion rents between the North and Houston zones is a prime example of a problem that lingered because of clashing financial interests. Nodal pricing of resources would have automatically priced the congested transmission lines around Houston and not required changes in the ERCOT protocols or lengthy debates on commercially significant constraint (CSC) designations as costs were mounting.

The commission likens the current wholesale market design to a person on a long trip driving a car down a highway with three good tires and a fourth tire that is badly worn and leaking. The driver can continue towards his destination for some period of time, but at a slower speed and with more frequent stops for repairs than he could drive with four good tires. Eventually, however, the driver will need to replace the tire before the end of the trip. The alternative, which would save time and money in the long run, would be to promptly replace the tire. Furthermore, replacing the tire sooner rather than later would reduce the risk of accidents.

A key reason for deregulating the electric industry in Texas was to devolve decision-making and to provide electric retailers and wholesalers with flexibility in the face of changing market conditions. Under PURA, the commission supervises, not micromanages, the electricity market. Decentralized decision-making based on economic forces is one of the key features of a successful competitive market, and automatic mechanisms to align incentives with good market outcomes make a wholesale market sustainable. A good price mechanism is vastly preferable to an administrative one, because QSEs should have the flexibility to choose the most cost-effective solutions to congestion charges and system reliability. Market participants who have the skill to handle risk/return tradeoffs inherent in a market (such as siting new resources) should be rewarded instead of those who have hired the better lawyer or have more clout at ERCOT stakeholder meetings. Profit margins can get squeezed in any competitive market, and the winners and losers are best left to the market rather than the commission or ERCOT.

Market risks should be allocated to market participants, rather than socializing those risks to customers who have no control over them, so that market participants can incorporate those risks into their business decision-making and manage those risks in the most effective way. The commission likens this philosophy to the game of handball: within the bounds of the court, the ball can go anywhere a player hits it. Just as the ball's motion is governed by the laws of physics, so too should market outcomes be governed by the laws of economics. Only in this way can market outcomes be self-correcting.

ERCOT is open to market forces, which at any given moment reflect investor psychology (e.g., the substantial over-building of combined cycle plants in ERCOT in recent years), stock market enthusiasms, changing tastes (such as renewable energy), and new technologies (such as fuel cells and smart meters). The ERCOT wholesale and retail markets are open to future opportunities that are not fully understood by market participants or regulators, and never will be.

Adoption of new or improved technologies often takes place in waves. Changing technology, changing relative prices, and changing consumer preferences often lead to everyone having the same great idea at the same time. Uncertainty about the size and scope of the market, the "unlimited potential," the fight for market share, the response to a government subsidy with a badly-designed expiration date (e.g., the December 31, 2001 expiration for eligibility for the federal production tax credit for wind resources), and the willingness to make a high risk / high reward bet will lead to these waves.

In this uncertain world, the markets will see waves of investment, shakeouts, and consolidations. The telecommunications industry provides another example of the unpredictability of deregulation. The telecom act of 1996 anticipated that long distance phone companies would be the chief competitors for incumbent local exchange carriers

(ILECs), and that the lure of long distance service would be the enticement for ILECs to allow competition in local services. The wireless revolution has significantly changed the dynamics of deregulation. Legislators and regulators did not fully anticipate how changing technologies and consumer preferences (i.e., consumers making long distance calls on wireless phones) would reduce the importance to ILECs of gaining access to long-distance telephone service.

Evolving markets need to have a set of rules that provide for price signals that act as shock absorbers for consumers as new market entrants and new products sort themselves out in the marketplace. The Texas nodal market design is far better equipped to handle these uncertainties than the current wholesale market design.

The technological dynamics of today's electric market are very different from the old world of regulation. Electric generation options are expected to include increasingly smaller-scale units. Consumers are expected to have a variety of technologies at their disposal to manage the timing, fuel source, and amount of electricity they consume. In 2001, ERCOT experienced a glimpse of this future when a combination of technological advances in wind turbine technology, high natural gas prices, and government subsidies combined to cause a wind rush in Texas described in the commission Market Oversight Division's (MOD's) September 9, 2002 filing in this proceeding.

As MOD explained in detail in that filing, the lack of direct assignment of local congestion rents leads to poor siting decisions for site-specific technologies such as wind.

CenterPoint commented that water and environmental restrictions on siting gas-fired generation limit the need for refined price signals in ERCOT. Not only does the commission disagree with this argument, it also disagrees with its premise that gas-fired plants should set the standard for resource price signals. Unlike gas-fired plants, wind resources do not need water or air pollution permits, which gives developers access to a large number of places where they can site a wind farm in the vast open spaces of West Texas. Even commercial wind farms often have less than 200 MW of nameplate capacity, sometimes less than 100 MW, which contrasts with some of the large-scale combined cycle and coal-fired plants. The commission sees the need for ERCOT to send more granular pricing signals to motivate developers to choose the most cost-effective sites to interconnect with the ERCOT grid.

Direct assignment of local congestion rents also will improve the siting of large thermal plants (e.g., combined cycle, gas-fired plants) in ERCOT. A plant that started operation in the northeast section of ERCOT in 2003 located in a spot that caused enough local congestion to have the Farmersville — Royce line considered as a new CSC for 2004. Another plant located in Wise County near the Dallas-Fort Worth metroplex is scheduled to go online in early 2004 in a place that could cause significant local congestion costs as well.

The need for nodal pricing of resources will be more acute as time passes. In this new competitive world, deployment of resources is faster and fraught with greater uncertainty. Wind farms can be sited and built within a year. Wind capacity at an existing site can be expanded in even less time. A developer might obtain a site for 150 wind turbines, build 100 now, and add 50 at an undetermined future date.

The commission also anticipates increased deployment of solar panels, fuel cells, and compressed air storage in the next five to ten years. The commission believes that the potential for technological advance and corresponding competition is an important reason for the deregulation of electricity markets. Distributed generation (DG), such as solar panels and fuel cells, may eventually grow into this quick-response model as well, and nodal pricing of resources and direct assignment of local congestion rents will be required to ensure that customers realize the greatest efficiency gains with the least amount of risk. Correct and site-specific valuation of power delivery costs is an indispensable part of DG's cost-benefit equation, and nodal energy prices and direct assignment of all congestion rents greatly furthers that goal.

Demand-side resources — such as residential and small commercial customers in metropolitan areas taking advantage of new technologies that will permit them to use time-of-use pricing and industrial customers providing market solutions to local constraints in congested urban areas such as the Dallas-Fort Worth metroplex and Houston — need direct assignment of local congestion rents as well. All of these technologies can be installed in a fraction of the time that coal or nuclear plants are built, which has the potential to change the way electricity is bought and sold and reduce the amount of expensive transmission built in urban areas.

Given current problems and future trends in wholesale and retail markets, the commission finds that the current zonal ERCOT market structure will become more and more arthritic in an increasingly dynamic market. The commission has a large amount of evidence in the record of this proceeding supporting this rule, which requires implementation of nodal pricing for resources with direct assignment of local congestion rents and resource-specific bid curves, in order to address the problems associated with uplifted congestion costs and poor incentives for siting and dispatching resources, as well as to improve the robustness and sustainability of the ERCOT wholesale market in the face of rapid and unpredictable changes in resource technologies and market conditions.

Comments

CPA generally supported the commission's cost-benefit estimate and provided clarification and alternative figures for specific cost-benefit items. CPA agreed with the commission that there will be savings as a result of improved, real-time economic dispatch under a nodal system, but noted that Dr. Schubert did not quantify such savings in the proposal for publication. CPA reported that a study by the Southeastern Association of Regulatory Utility Commissioners (SEARUC) assessed a market structure that is very similar to the proposed Texas nodal model and showed that the area of the proposed SeTrans regional transmission organization generally has positive net benefits both to native load and overall. According to CPA, this finding is relevant to ERCOT because, similar to certain parts of SeTrans, ERCOT does not currently use a coordinated, economic security-constrained dispatch. Using this study as a benchmark for the ERCOT region, CPA indicated that a 0.5% to 1.0% reduction in generation price would be a reasonable proxy of the potential benefits of moving to a centrally coordinated, bid-based, security-constrained economic dispatch under a Texas nodal system. Based on this proxy and $12 billion as the cost of fuel and purchased power in the ERCOT region (amounting to 75% of the ERCOT wholesale market cost), CPA estimated that fuel and purchased-power savings from implementing a centrally coordinated, bid-based, security-constrained economic dispatch as part of a Texas nodal system would range from $60 million to $120 million per year.

Commission response

The commission believes that CPA's estimate of the benefits from improved dispatch in real-time that would result from Texas Nodal, is reasonable, which adds further support for the commission's conclusion that the benefits of Texas Nodal substantially outweigh its costs. The commission has revised its cost-benefit analysis to include these benefits.

Comments

CPA presented its own estimate of the cost to QSEs to implement a Texas nodal system. CPA's total net present value of quantifiable QSE implementation costs over the first five years of implementation was $30 million to $70 million, compared to the commission's estimate of $90 million. CPA's estimate was based on an initial capital expenditure of $750,000 to $1.5 million for each of the 19 active QSEs and an on-going requirement of one to three additional staff per QSE at $200,000 for each additional person. CPA noted, however, that on-going maintenance should be no different from the on-going maintenance costs of existing systems and that QSEs' existing personnel resources should be more than adequate.

Commission response

The commission believes that its $90 million estimate is reasonable, but acknowledges that the cost may be substantially lower.

Comments

CPA derived an overall estimate of the net present value of net quantifiable savings of between $281 million and $626 million over the first five years of implementation of a Texas nodal system. This amount incorporated the commission's estimates for reduced OOME Down costs, reduced transmission construction costs, improved siting of wind farms, and ERCOT's implementation costs, as well as CPA's own estimates for the potential elimination of overlap or "throw-away" projects, reduced generation prices through improved real-time economic dispatch, and QSEs' implementation costs. CPA estimated that, even without the savings from reduced generation prices, the savings are between $28 million and $120 million over the first five years of implementation.

Commission response

The commission acknowledges that it did not quantify all of the benefits of Texas Nodal in the preamble to the proposed rule, and that quantifying some or all of the additional benefits identified by CPA would increase the estimated net benefit of Texas Nodal.

Comments

CPA supported the $50 million estimate of ERCOT's cost to implement a nodal system, which estimate was based on ERCOT's April 18, 2003 filing in this project. CPA also pointed to AEP's estimate of ERCOT's one-time implementation costs ranging from $25 million to $35 million.

Denton/Garland challenged CPA's assertion that there is sufficient evidence for the commission to decide now to move forward with the design and implementation of a Texas nodal market. Moreover, Denton/Garland argued that there is a high probability that the estimated costs in the cost-benefit analysis are understated, noting that the cost to transition ERCOT and market participants to the new market design could be significantly higher. They pointed out that ERCOT, after providing its initial estimate of $35 million to $50 million, determined that the $50 million was a minimum.

Commission response

With respect to Denton's concern about ERCOT's cost of converting to a nodal system, AEP projected a conversion cost of $25 million to $35 million, ERCOT estimated a conversion cost of $50 million, and MOD filed information in this proceeding in August 2002 based on costs of converting other U.S. electric wholesale markets to a nodal design. MOD's estimates are consistent with the $50 million cost estimate used in the cost-benefit analysis in the preamble. As a result, the commission believes that it has sufficient evidence in the record to support the $50 million estimate.

Comments

CPA noted AEP's estimate of on-going, increased costs of $2.14 million per year for ERCOT, which the commission did not include in its cost-benefit analysis. Denton/Garland also questioned whether the $50 million includes ERCOT's June 17, 2003 estimate of the need for 70 additional staff and consultants by June 2004 to implement a nodal design.

Commission response

The commission agrees with CPA that the commission's cost estimate in the preamble to the proposed rule did not include the additional operation and maintenance costs to ERCOT of implementing a nodal system, and that these costs are properly included in a cost-benefit analysis. The commission has revised its cost-benefit analysis to include these costs.

Comments

Denton/Garland also expressed concern that the commission's assumption that 20 QSEs will be affected is too low, because a recent ERCOT report states that there are currently 85 QSEs (of which 80 are active) and that there could be 126 QSEs by the end of 2004. Denton/Garland recognized, however, that it was uncertain whether the market design will affect only QSEs that represent generation or all QSEs.

Commission response

The commission disagrees with the use of 80 QSEs to calculate the cost of conversion. CPA, which includes a number of market participants, used 20 QSEs in its estimates of converting to a nodal system, as did the ERCOT Coalition in its January 2003 filing. Commission staff has reviewed the active number of QSEs to confirm that the numbers both CPA and the ERCOT Coalition used are a fair representation of the QSEs that will experience substantial conversion costs. The QSEs that schedule generation in ERCOT will need to submit unit-specific bid curves to the ERCOT operator, which will require these conversion costs.

Comments

In addition, Denton/Garland questioned the commission's estimate of an individual QSE's implementation costs. They requested that commission staff provide a detailed explanation of how it moved from the $2.2 million estimate of start-up costs to a range of $1.5 million to $2 million, including an explanation of cost category items that were excluded or adjusted. Denton/Garland suggested that the estimate is, in all probability, too low if the commission used the cost estimates provided by Reliant ($1.5 million) and LCRA ($2 million to $2.2 million).

Commission response

In August 2002, MOD asked two market participants, LCRA and Reliant, to provide the commission with estimates of the cost of moving to a market design based on nodal pricing of resources, and the commission relied on these estimates in its cost-benefit analysis. Denton/Garland assert that these cost estimates are too low, but provide no information to dispute these numbers.

Comments

Denton/Garland noted that not all market participants possess the level of in-house personnel and information-technology resources that some market participants possess, and that implementation of a nodal system will probably be more expensive for smaller market participants.

Commission response

The commission agrees that there are economies of scale in participation in competitive wholesale electricity markets, but would note that most of the functions impacted by the rule are competitive; many market participants already use unaffiliated QSEs for scheduling and settlement services. Therefore, a small market participant has the option of contracting for scheduling services rather than developing and maintaining its own scheduling capability.

Comments

Denton/Garland concluded that there is a negative value for implementation of a nodal design under all but the ten-year, high-benefit case if ERCOT's start-up costs are increased from $50 million to $75 million, the number of QSEs is increased from 20 to 80, and a QSE's one-time start-up costs are increased to $2.2 million.

Commission response

Consistent with the discussion above, the commission believes that the higher costs Denton/Garland describe are not a good representation of the costs that likely will be incurred in implementing this rule. Therefore, the commission declines to incorporate the changes that Denton/Garland proposed.

Comments

Denton/Garland expressed even greater concerns with the benefits in the commission's cost-benefit analysis. They questioned why the elimination of OOME Down payments should be attributed to a nodal market design. They asserted that there is no real benefit to the ERCOT market, regardless of whether the purported benefit results from replacing OOME Down payments with balancing-energy-down service or from an assumption that higher nodal prices will force more economic dispatch, thus avoiding the need for an OOME Down instruction.

ERCOT also questioned the expectation in the preamble that a nodal system will reduce local-congestion costs. ERCOT indicated that although costs may be reduced, the potential magnitude of change and the potential cost redistribution are unknown at this time. According to ERCOT, much of the projected cost "savings" will not disappear, but rather may be allocated differently.

Commission response

The commission disagrees with the comments of Denton/Garland and ERCOT that OOME Down costs would not decrease but instead only be reallocated under Texas

Nodal. The commission has determined that OOME Down payments create strong incentives for resource owners to game the ERCOT market. In contrast, direct assignment of congestion rents reduces local congestion costs/payments, because resource owners would no longer be able to play the decremental (DEC) game.

The DEC game occurs when (1) a market participant submits a schedule that if followed would cause congestion; (2) the market participant is paid to "solve" the anticipated congestion by generating less than what was scheduled; and (3) the cost of these local congestion payments are socialized. If participants are not charged for creating congestion when they schedule too much flow over a constrained local line, then they have an incentive to schedule as much output as possible in order to collect payments to generate below scheduled output. The money spent on the DEC game is an unnecessary and economically unsound subsidy from retailers and their customers to resource owners, not a redistribution of costs among market players.

Interzonal overscheduling was a major problem in August 2001 when the market opened, because zonal congestion costs were socialized. In contrast, interzonal overscheduling has not been a problem since February 2002, when direct assignment of zonal congestion rents began. The commission rejects the argument that costs are only shifted, and not reduced, through direct assignment of congestion rents.

Comments

Denton/Garland also stated that the cost-benefit analysis fails to recognize that there will be winners and losers, both for generation and loads, under a nodal market.

Commission response

The commission acknowledges that nodal prices for resources will be higher in some locations and lower in others under nodal pricing for resources, although the zonal energy prices for loads required by the rule can be used to moderate, if not eliminate, this impact on loads. As the ERCOT Coalition and TXU noted in their filings of January 31, 2003, differing zonal prices have changed resource siting behavior, resulting in resources siting in zones that are relatively resource deficient, and thereby reducing the amount of transmission needed to bring electricity from resources to load. Price signals are dynamic, because resources that locate in a high priced area will tend to lower prices in that area. Because in a nodal market new resources will locate where they can produce and deliver electricity most cost effectively, they will lower the overall cost of electricity in the future compared to the current zonal market. Over time, all retailers and their customers benefit, some more than others.

Comments

Denton/Garland questioned how nodal pricing would create the benefits in the commission's cost-benefit analysis that were associated with the McCamey area. They argued that the need exists today for additional transmission capacity to allow all of the potential generation in McCamey to enter the ERCOT market. If the cost-benefit analysis is implying that nodal pricing would have avoided the situation, Denton/Garland requested an explanation concerning how such benefits could be guaranteed.

Commission response

Currently, ERCOT has just over 1,000 MW of installed wind capacity. Initially, most of the wind development was concentrated in the McCamey area; consequently, transmission constraints have arisen. Transmission projects are underway to enable the flow of existing wind generation, but it will take years before those transmission projects are completed. Furthermore, according to information about transmission upgrades in West Texas filed by commission staff in this proceeding on May 6, 2003, significant transmission upgrades of at least $150 million would be needed if new wind development remains concentrated in the McCamey area.

Denton/Garland claims that the commission has not conducted studies on the impact of poor pricing signals on the siting decisions of wind farms. The commission disagrees with that assertion, and believes that MOD's filing on September 9, 2002 provides sufficient evidence of how the siting of wind farms would have been different under direct assignment of local congestion rents.

Implementing direct assignment of local congestion rents will help prevent new wind farms from outracing transmission construction, as they have done in the past. If direct assignment of local congestion rents had been in place at the opening of the market, wind resources would have faced substantial economic penalties for overbuilding in the McCamey area, and the commission finds it reasonable to conclude that a very substantial amount of the excess capacity of wind resources in the McCamey area would not have been built in that area.

Direct assignment of local congestion rents automatically and systematically puts the onus of a poor siting decision on the developer of a wind farm. The overbuilding of wind farms behind the McCamey constraint arose in part because of the OOME Down payments that made wind developers indifferent about building a wind farm where they could actually deliver their power to loads. The lack of sufficiently granular pricing for resources failed to penalize the wind developers sufficiently. The wind developers sited their new wind farms inefficiently, and ERCOT and the commission, in order to meet the renewables mandate in PURA, responded by building more transmission in the McCamey area. Direct assignment would help prevent a repeat of this "build the wind farm and the transmission will come" approach. In addition, the OOME Down payments provided wind resource owners in the McCamey area with a substantial incentive to overschedule wind resources. Wind resource owners reaped the benefits of this costly loophole. In the period from August 2001 to August 2002, wind resource owners received more than $10 million in OOME Down payments, which were charged to loads.

There are a number of wind development sites available in ERCOT and some in non-ERCOT areas of Texas capable of meeting the renewables mandate without requiring costly transmission upgrades. Although the McCamey projects may produce higher resource capacity factors, this benefit does not necessarily offset higher transmission costs required to deliver the power to market. Direct assignment of local congestion rents would provide wind developers with a strong incentive to efficiently site their projects. The ERCOT transmission system can accommodate much more wind capacity without expensive transmission upgrades if new facilities are appropriately sited.

Comments

Denton/Garland challenged the benefits related to reduced transmission costs and argued that there is no support for the assumption that such costs will decrease between 20% to 30% per year under a nodal modal. They suggested that these costs will be offset by increased OOM costs, balancing-energy costs, or higher nodal generation prices that will be borne by a subset of the ERCOT market. If the commission's analysis implies that nodal pricing will reduce costs through more efficient transmission planning, Denton/Garland suggested that an improved transmission planning process can be developed without nodal pricing. They also cited an April 2003 *Public Utilities*

Fortnightly article that stated that LMP has not been adequate in providing transmission-expansion incentives.

ERCOT noted that although the commission's assumption that the rate of transmission-construction costs in ERCOT will be permanently reduced by 20-30% may be true in some circumstances, many considerations in addition to nodal prices are also significant in resource investment and siting decisions.

ERCOT indicated that the commission should view with caution the purported benefits presented in the preamble to the proposed rule. Specifically, ERCOT also noted that a reduction in transmission investment without an offsetting investment in, or change in location of, expected load or generation may not be a positive benefit and could endanger service reliability.

Commission response

The commission agrees with Denton/Garland and ERCOT that nodal pricing does not automatically produce new transmission. However, the commission, ERCOT, and transmission service providers (TSPs) have been very aggressive in building new transmission in ERCOT compared to other regions in the United States. The commission disagrees with ERCOT's suggestion that reduced transmission construction under Texas Nodal will cause a problem, because the more granular pricing signals will improve the siting decisions of resource developers. Nodal pricing sends better pricing signals, but the commission, ERCOT, and TSPs will still need to act to build transmission when it is the most cost-effective means of solving a constraint. The price signals that nodal pricing generates will provide the commission, ERCOT, and TSPs with better estimates of the costs of congestion on various lines across ERCOT, which will assist the commission in deciding which transmission lines to build. These pricing signals will also encourage the use of distributed generation and demand-side resources, which can be alternatives to new transmission lines in some cases.

Comments

Denton/Garland questioned how potential generators in a transmission-constrained, non-attainment area would overcome the lack of air permits, land, gas capacity, and water needed to support the development of new generation, even if nodal pricing were to send a high price signal in the area. Denton/Garland requested that commission staff provide a detailed explanation of the assumed benefits and empirical evidence that nodal pricing will achieve the level of benefits assumed in the cost-benefit analysis, and not just result in cost shifting between market participants. They voiced concern that even if the analysis is correct, the benefits and costs will not fall equally on all parties. They noted that congestion costs under a nodal model do not disappear, but are, for the most part, reallocated from the whole system to urban areas of high load density that must rely on transmission lines to import generation supply. Denton/Garland pointed out that high-priced load pockets can suffer from exposure to excessive congestion rents and that the implementation of nodal pricing will not resolve this dilemma unless all loads are assigned costs on an ERCOT-wide basis.

Commission response

The Dallas Fort-Worth area (DFW) is a prime example of the need to encourage alternatives to constructing new transmission. According to information filed by commission staff on May 9, 2003, the expense of upgrading transmission in the DFW area is substantial. Alternatives to building new transmission will be increasingly economical by the time Texas Nodal begins operating in Texas in late 2006. Direct assignment of congestion rents as envisioned in this rule will interact with new technologies and will encourage demand-side services and distributed generation. Loads acting as resources (LaaRs) do not require air permits, gas capacity, land, or water. Distributed generation such as fuel cells can be placed in areas where gas-fired plants would be infeasible or unprofitable because of environmental restrictions. The commission still could order a transmission solution if transmission is the most cost-effective alternative, but transmission in urban areas is costly and subject to substantial landowner resistance. The more accurate price signals required by this rule will help ensure that the most cost-effective alternatives are selected. Furthermore, although nodal pricing for resources may increase payments to resources in some urban areas, the impact on loads in these areas can be reduced, if not eliminated, through the rule's requirement that loads be subject to zonal, rather than nodal, prices.

Comments

STEC asserted that the commission's cost-benefit analysis fails to quantify the impact of having winners and losers among market participants, as well as different regions of the state. STEC noted that the ability to attract a generating plant in a rural area can have a large impact on neighboring local governments, schools, job creation, and small businesses. According to STEC, the commission should ensure that no area of ERCOT suffers economic harm from implementation of a nodal system and, in particular, that poverty in rural areas is not exacerbated.

Commission response

As discussed above in connection with question 5, the commission expects ERCOT to include in its cost-benefit analysis required by subsection (m) of the final rule, an analysis of benefits and costs on a region by region and market segment by segment basis. Furthermore, the commission, through its traditional transmission planning process supplemented with more complete locational pricing information, can provide the opportunity for generation to locate throughout the rural parts of ERCOT if transmission expansion is cost-effective. The commission notes that direct assignment of congestion rents will distribute wind resources more widely throughout West Texas. As such, county governments and school districts will more broadly reap the benefits of the new wind generation through local taxes and higher employment.

Comments

ERCOT stated that investment in generation and responsive demand may not necessarily occur where it is most beneficial. ERCOT suggested that, as part of the market design process, it lead the analysis of the impact of a potential change to a nodal system on transmission planning and on rules for interconnection and existing agreements. ERCOT also stated that, although the commission intends to enforce and administer the rule through the use of existing resources, the commission might need to evaluate the magnitude of its market-monitoring role under the new market design. If additional staff is needed to support planned activities, ERCOT urged the commission to consider how its efforts will be supported.

Commission response

The commission appreciates ERCOT's effort to identify issues resulting from implementing Texas Nodal. The commission believes that today it has adequate resources for market monitoring for Texas Nodal, particularly with the increased appropriations for market monitoring that will take effect on September 1, 2003.

Comments

Magic Valley, Mid-Tex, and Rayburn also questioned whether the objective of having generation locate near load centers is appropriate from an overall policy standpoint, which includes consideration of environmental and broader economic goals.

Commission response

Installing transmission lines in large, urban areas is an expensive and lengthy process that meets strong landowner resistance. Demand-side resources and distributed generation (e.g., fuel cells and solar panels) in certain instances may be a less expensive means for addressing increases in peak demand in congested urban areas than building new transmission lines. Nodal pricing of resources will make the decision whether to build additional transmission more transparent.

Comments

CPA noted that some of the projects to improve the existing system might overlap some aspects associated with the implementation of a nodal system; therefore, some of the costs to improve the existing system may be reduced either by eliminating these projects or by tailoring them to be functional under both the current system and Texas Nodal. LCRA cautioned that major design changes will be disruptive and should not be undertaken without a clear understanding of the incremental benefits and costs of such changes. According to LCRA, costs include not only hardware and software costs to ERCOT and market participants, but also the operating costs associated with learning and implementing a new system.

Commission response

The commission acknowledges that CPA and LCRA have identified additional cost reductions and increases, respectively, which were not included in the commission's cost-benefit analysis in the preamble to the proposed rule. However, neither CPA nor LCRA quantified these reductions and increases, and the commission does not believe that they materially affect its conclusion that the benefits of Texas Nodal will substantially exceed its costs.

In response to stakeholder comments, the commission has updated the cost-benefit analysis presented in the proposal for publication. For the first five years after the effective date of the rule, the commission estimates the net present value of the quantified benefits of converting to a Texas nodal market design range from $262 million to $402 million. For the first ten years after the effective date of the rule, the commission estimates the net present value of the quantified benefits of converting to a Texas nodal market design range from $643 million to $1.08 billion.

The commission calculates the net present value of the quantified costs of converting to a Texas nodal market design in the first five years of the implementation of this rule to be between $137 million to $146 million. The commission calculates the net present value of the quantified costs of converting to a Texas nodal market design in the first ten years of the implementation of the rule to be between $269 million to $279 million.

The commission calculates that the net present value of the net benefits of converting to a Texas nodal market design in the first five years of the implementation of this rule to be between $115 and $265 million. The commission calculates that the net present value of the net benefits of converting to a Texas nodal market design in the first ten years of the implementation of this rule to be between $364 and $813 million. As this analysis shows, the benefits of implementing a Texas nodal market design increasingly outweigh the costs when reviewing time periods longer than five years.

Comments on Specific Parts of the Proposed Rule

Subsection (a)

Comments

Reliant, TXU, and San Antonio recommended deleting the requirement in subsection (a) that the ERCOT rules and protocols be consistent with established economic principles. TXU argued that this requirement is vague, undefined, potentially inconsistent with PURA, and likely unenforceable. TXU asserted that no two economists can agree on the exact nature of "established economic principles" and that the term "marginal cost pricing" is not defined. TXU also questioned what would happen if an economic principle contradicted an engineering principle. TXU suggested that the inclusion of this language in the rule would invite unnecessary and contentious debate over market design, and would risk the entire rule being rejected by the courts as "void for vagueness." Furthermore, TXU argued that the requirement that ERCOT protocols and rules be based on marginal-cost pricing is inconsistent with PURA. Although TXU proposed deleting the reference to economic principles, including marginal-cost pricing, it recommended retaining the requirement to minimize social costs. Reliant stated that it must be clear that the general intent of the rule is to support the direction of Senate Bill 7 and PURA in supporting competition and reliability through market solutions. Reliant recommended that the emphasis of subsection (a) be on the need to facilitate a robust, competitive market and to support reliability. Reliant noted that economic principles need to be balanced with how market rules support competition and with operational constraints. San Antonio argued that strict requirements of this nature, while conceptually laudable, are often practically or politically unachievable. San Antonio noted that there are several features in the current market that are inconsistent with the specified attributes and that certain deviations from these global principles may be desirable in any future market design. Moreover, San Antonio pointed out that one example that would violate these principles is actually a requirement in subsection (d)(5) of the proposed rule, relating to zonal energy prices for loads. Other examples cited by San Antonio included ancillary service obligations, transmission losses, and the ERCOT fee. Therefore, San Antonio proposed deleting the requirement that the protocols and rules be based on established economic principles, as well as the requirements related to supporting competition and reliability. San Antonio proposed new language in subsection (a) that would require the protocols and rules to be designed to facilitate competition in the sale of electric energy in Texas, preserve the reliability of electric service, and enhance economic efficiency in the production and consumption of electricity. San Antonio proposed a definition of locational marginal pricing (or nodal energy price) to include in the rule. This definition would be based on an algorithm intended to minimize total energy costs for the ERCOT region, subject to constraints reflecting physical limitations of the power system, and would contain three components of a nodal price: an energy component, a transmission-loss component, and a congestion component.

Commission response

Just as it is essential for the physical ERCOT system (generation facilities, transmission facilities, etc.) to be designed taking into consideration engineering principles, it is essential for the ERCOT competitive market to be designed taking into consideration economic principles. Indeed, it was ERCOT's failure to adequately use the economic principle of marginal cost pricing that prompted this rulemaking. In particular, in approving the original ERCOT competitive market design in Docket Number 23220, the commission ordered ERCOT to begin directly assigning local congestion rents once local congestion costs rose above a $20 million, twelve-month threshold. Many ERCOT stakeholders took the position that directly assigning local congestion rents was fundamentally inconsistent with the zonal market design. Consequently, the commission initiated this rulemaking to require a design that directly assigns all congestion rents and, in addition, to prescribe other fundamental requirements for the ERCOT wholesale market design.

The ERCOT wholesale market design protocols generally reflect thorough consideration of engineering principles. However, major protocols have at times failed to reflect adequate consideration of economic principles. Therefore, it is important that this commission rule, which addresses fundamental requirements for the ERCOT wholesale market design, require consideration of economic principles. The rule has been modified to make it clear that the commission's intent in referring to economic principles is not to prescribe a specific outcome, but rather to require consideration of economic principles, along with other important factors, in ERCOT's development of wholesale market design protocols. Nevertheless, as reflected in the commission's review of the original ERCOT wholesale market design in Docket Number 23220, it is essential that when ERCOT's procures ancillary services through auctions and manages power congestion on the transmission system, ERCOT use economic concepts and principles such as shadow price of a constraint, marginal cost pricing, and maximizing the sum of consumer and producer surplus. The commission has amended subsection (a) of the final rule accordingly.

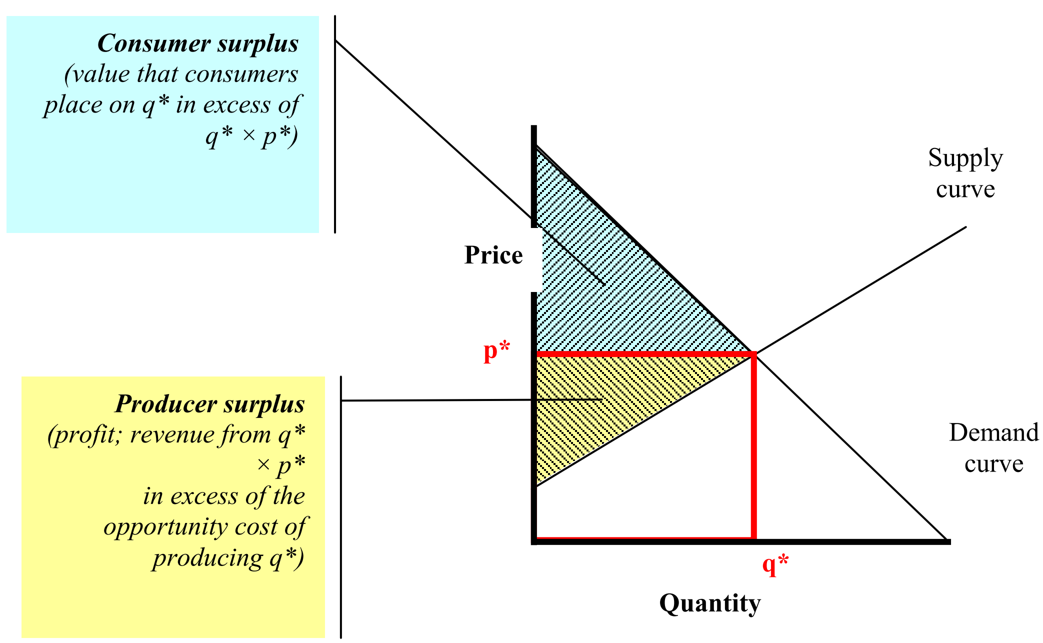
A market where the product is purchased at a single clearing price is considered efficient when the clearing price equals the marginal cost of a producer that provides the last increment purchased (i.e., marginal cost pricing).

A market clearing price that maximizes the sum of consumer and producer surplus is considered an efficient outcome. Consumer surplus is the area below the demand curve and above the market clearing price. Producer surplus is the area above the supply curve and below the market clearing price. Figure 1 illustrates these concepts.

If a market clearing price is associated with an operational constraint, then an efficient outcome is where the shadow price of a constraint sets the market clearing price of that constraint. The shadow price of a constraint is the increase in consumer and producer surplus that would result from a small relaxation of the constraint. For instance, if a one MW increase in the flow limit of a transmission line would reduce the cost of delivered power by $30 per MWh, then the shadow price of the line is $30 per MWh.

Figure 1: 16 TAC Chapter 25 - Preamble

Consumer and Producer Surplus



Although marginal cost pricing is a sufficient condition for achieving consumption and production efficiencies in simple commodities, the interpretation of marginal cost requires further clarification when prices reflect scarcity rents or constraints. Such cases arise when pricing congestion, pricing CRRs, or procuring ancillary services through auctions. In these instances, marginal cost pricing is interpreted as the shadow prices on constraints that are defined as the incremental improvement in the objective function of the underlying optimization (e.g., optimal security-constrained dispatch, optimal awards of CRRs, or optimal procurement of ancillary services).

Shadow prices on constraints have no meaning without specifying the objective function of the optimization, and the only objective function that is consistent with marginal cost pricing is maximizing the sum of producer and consumer surplus, also known as the social surplus. Social surplus is a well-defined concept in economics. It is the difference between the total valuation of the product by the buyers and the total production cost to the seller. In a uniform pricing regime with prices set to the shadow prices, buyers will have the incentive to reveal their true valuations and sellers have the incentive to reveal their true costs. As a result, the social surplus is represented by the sum of the demand bids minus the sum of the supply offer prices for the traded products. In a case where a fixed capacity is being auctioned off, as in the case of CRR auctions, there is no short-run supply cost, so the objective of maximizing the sum of consumer and producer surplus is equivalent to maximizing the "as bid" value of the CRRs. Likewise, when demand is inelastic, as in the case of ancillary capacity service procurement, consumer surplus is fixed (infinity), so maximizing consumer and producer surplus is equivalent to minimizing the "as bid" cost of the procured ancillary services.

Using any other objective function such as minimization of procurement costs (which is equivalent to maximizing just consumer surplus) will result in socially inefficient outcomes. Departure from uniform prices that are set to the constraints' shadow prices, such as a "pay as bid" approach, generally will distort consumers' and producers' incentives to reveal true valuations or true costs, and therefore distort the objective function, resulting in socially inefficient outcomes. The only mechanism that is fully incentive compatible (induces truthful revelation of information, assuming that there is no market power, which should be addressed separately) and results in efficient consumption and production of goods and services is the maximization of social surplus (i.e., total valuation minus total production cost as reflected by demand and supply side bids) through uniform pricing set to the constraints' shadow prices, which are interpreted as marginal cost prices.

The rational buyer approach to reserve procurement in California departs from the above principles by minimizing procurement cost of reserves, i.e., consumer surplus, rather than the sum of consumer and producer surplus. It is well-documented that this approach can result in inefficient procurement. For example, an expensive offer for spinning reserves can be selected, while a less expensive offer for (faster responding) regulation reserves that could meet the same need but would have raised the market clearing price for regulation will be rejected. That approach will often result in price reversal, where the clearing prices for fast responding reserves will be below those of the slow responding reserves, which can induce bidders to distort their bids by understating their capability to provide fast responding reserves.

With the revised language in subsection (a) and a more detailed discussion of the language in subsection (a) in the preamble to the rule, the commission has addressed TXU's argument that subsection (a) is vague. The commission acknowledges that it may be difficult for the general public to understand subsection (a), but the same is true of many of the commission's rules, because they address complex, technical issues. Competitive electricity wholesale market design is very complex and technical. The terms used in the rule are terms used in economics and the wholesale competitive electric industry. The commission has not prescribed specific definitions for the terms in the rule in order to avoid unnecessarily limiting ERCOT's flexibility in implementing the rule.

The commission agrees with San Antonio that a key objective for the market design is the promotion of economic efficiency in the production and consumption of electricity, and has incorporated this objective in subsection (a). However, the commission declines to incorporate San Antonio's definition of nodal energy price into the rule. The commission's goal in enacting this rule is to prescribe fundamental market design elements that it believes are essential, while leaving ERCOT the flexibility to address many other important design elements, such as the precise definition of nodal energy price.

Subsection (b)

Comments

ERCOT proposed revisions to subsection (b) to clarify that ERCOT does not take title to energy. ERCOT noted that it acquires energy on behalf of market participants and allocates the costs of such acquisition to the parties receiving the services. Reliant also proposed changes to subsection (b) to clarify that ERCOT procures energy and ancillary services as needed on behalf of the market participant, and shall charge that market participant for ERCOT's procurement costs. In addition, Reliant suggested adding a provision stating that ERCOT will procure energy and ancillary services if a market participant's contracts are undeliverable.

Commission response

The commission finds that ERCOT's and Reliant's proposed clarification concerning ERCOT's purchases on behalf of market participants is appropriate and amends subsection (b) accordingly. The commission also amends subsection (b) to clarify the concept of self-arrangement of ancillary services. As to Reliant's proposed reference to undeliverable contracts, the commission amends the rule to make clear that ERCOT shall procure ancillary services to the extent necessary to cover self-arranged services that ERCOT determines will not be delivered.

Comments

San Antonio proposed modifying subsection (b) to clarify that the charges for ancillary services or energy shortfalls are based on the marginal, rather than the average, cost of procurement. San Antonio also proposed distinguishing between energy and ancillary services by using "and/or" instead of "and" in this subsection.

Commission response

The commission is concerned that a requirement for ERCOT to charge the marginal cost of procurement may not be appropriate in all circumstances, and therefore declines to make San Antonio's change in this regard. Energy procured by ERCOT is a type of ancillary service. Therefore, the commission will not make the "and/or" change proposed by San Antonio.

Comments

Reliant and San Antonio proposed deleting the reference in subsection (b) that limits self-arrangement when it would adversely affect ERCOT's ability to maintain reliability. Reliant indicated that it was difficult to imagine a situation in which a market participant's self-arrangement would lead to adverse reliability impacts. To the extent that it would, Reliant pointed out that there are various market incentives to communicate the financial consequences of commercial decisions and that the system operator has the ability to redispatch the system to alleviate the concern. Reliant suggested that this phrase in the rule is contrary to how such events are addressed in the protocols. San Antonio added that to the extent self-scheduling or bilateral contracts create a reliability concern, this would be a result of poor market design. San Antonio proposed addressing in the market-design process valid concerns, if any, in this regard. In addition, AEP proposed revising this provision in subsection (b), because it would be difficult for a single market participant to be aware of all of the reliability ramifications resulting from a transaction. AEP indicated that it would be more appropriate for the rule to state that market participants shall conduct these transactions pursuant to current market protocols.

Commission response

The commission agrees that self-arrangement for most ancillary services in most circumstances will not adversely impact ERCOT's ability to maintain reliability. However, reliability of the ERCOT grid is paramount, and therefore the rule should provide ERCOT the flexibility to take actions necessary to maintain reliability.

Subsection (c)

Comments

Denton/Garland stated that the design of a nodal market is not dependent on having a day-ahead market or power exchange, but the design of a day-ahead market or power exchange is very dependent on the final market design. Therefore, Denton/Garland suggested that a day-ahead market design would be undertaken most efficiently after the final design is complete.

Commission response

The commission agrees that a nodal market does not require a day-ahead market. Nevertheless, a day-ahead market is necessary to improve market liquidity, promote greater price transparency, and increase demand-side responsiveness to the ERCOT wholesale market. It therefore should not be delayed. Furthermore, the decision as to whether the day-ahead market will reflect congestion and be financially binding will likely affect other market design elements, for example whether congestion rights are settled using day-ahead schedules.

Comments

Reliant proposed that subsection (c) be clarified to reflect the goals being sought by the commission, including price transparency and increased opportunities to achieve price certainty, and to ensure that the day-ahead energy market is consistent with other components of the competitive market.

Commission response

The goals mentioned by Reliant are consequences of a day-ahead market, and it is therefore unnecessary to list them as goals.

Proposed subsection (d)

Comments

Austin stated that the initial phase of developing a wholesale market model will be the most difficult, and recommended that this initial phase be extended by three months. San Antonio concurred that there needs to be more flexibility in the timeline for initial design; it recommended that the January 1, 2004 date be removed altogether and that the July 1, 2004 date represent a date for the submission of initial protocols. San Antonio stated that not all details of the new design should be set in stone on that date.

Commission response

The commission agrees with Austin and San Antonio that the timeline for implementing a Texas nodal market design needs to be more flexible and has removed the January 1, 2004 deadline for completing a conceptual and detailed market design from the rule.

Comments

ERCOT suggested changing the language in subsection (d) to indicate that ERCOT should develop the wholesale market model with input from the stakeholders. Its proposed first clause in subsection (d) reads as follows: "By January 1, 2004, ERCOT shall develop a wholesale market model*, soliciting input from a stakeholder process* that includes the following characteristics."

Commission response

The commission declines to make this change. It is very important that ERCOT use a stakeholder process to develop the market design, because stakeholder input is essential to the success of the design. Nevertheless, the commission expects that ERCOT staff will be actively involved in the development of the market design, and that the ERCOT Board (along with the commission) will oversee the development process and will decide what market design to submit to the commission for approval.

Proposed Subsection (d)(1); Final Subsection (d)

Comments

San Antonio noted that, in accordance with the requirements of proposed subsection (d)(7), ex ante mitigation may be applied in some cases, so that the actual bid curves are not used for the purposes identified in proposed subsection (d)(1). To avoid confusion, San Antonio suggested adding the language "or ex-ante mitigated bid curves, where appropriate," after the words "ERCOT shall use these bid curves."

Commission response

The commission agrees with the modification that San Antonio has proposed, in order to clarify the language in final subsection (d) (proposed subsection (d)(1)). The commission also amends this subsection to include the concept of market failure, in order to tie the requirements in this subsection and final subsection (j) (proposed subsection (d)(7)), which addresses pricing safeguards in general.

Comments

Reliant stated that if the commission adopts resource-specific bidding and scheduling, financial settlement should reflect the same regime, in order to avoid creating a disconnect in market incentives. Accordingly, Reliant recommended adding "and financial settlement" to the end of subsection (d)(1).

Commission response

The rule already contains the language Reliant suggested.

Comments

CPA opined that proposed subsection (d)(1) should address the provision of market information to participants while honoring the confidentiality of commercially sensitive information.

Commission response

The commission has addressed this issue in connection with Question 2, above.

Proposed Subsection (d)(2); Final Subsection (e)

Comments

CPA asserted that proposed subsection (d)(2), as drafted, does not reflect the commission's intent regarding pricing and allocation of costs. CPA stated that marginal-cost pricing, as proposed for the implementation of Texas Nodal, recognizes that the price of energy may vary at different locations and times because transmission congestion limits the transfer of electricity between different locations. CPA further stated that the marginal price of energy at a particular location and time reflects the additional cost (the cost of congestion) of procuring the last unit of energy at a location; the sellers are paid the marginal price at their node; and the buyers pay the marginal price for the zone in which their load is located. Therefore, the marginal price for a zone is the load-weighted average of the LMPs for the nodes located within that zone, resulting in the allocation of the congestion costs falling directly out of the marginal pricing to either the buyer or the seller.

CPA recommended changing the congestion-pricing language in subsection (d)(2) of the proposed rule to the following:

"Marginal cost pricing shall reflect the cost of congestion as measured by the difference between the marginal price of energy at different locations on the ERCOT transmission system. All suppliers selling at a node receive the LMP at that node. Similarly, all buyers purchasing within a zone pay the locational marginal price for that zone. Thereby, the cost of congestion shall be directly allocated as an inherent function of locational marginal pricing."

San Antonio advocated deleting all of proposed subsection (d)(2), contending that it contains language that is both unnecessary and misguided. The nodal-pricing features incorporated in the rule, San Antonio asserted, will inherently result in prices for all generation and load that reflect the value of power at each location, in consideration of congestion and any other constraints. If there is congestion, San Antonio continued, a nodal model will reflect the varying economic value of power across the grid, causing ERCOT to collect more revenues from LSEs than are paid to generators (excluding any payments to holders of congestion revenue rights). San Antonio concluded that the difference in revenues and receipts is congestion rent, so there is no need for artificial assignment mechanisms. Moreover, San Antonio cautioned that the aspects of proposed subsection (d)(2) concerning congestion-cost causation and assignment may actually conflict with the core functionality of the nodal algorithm. San Antonio also presented a definition of nodal pricing in its comments, as discussed in subsection (a). In its reply comments, CPA agreed with San Antonio that nodal bidding, dispatch, and pricing will result in automatic and proper assignment of congestion costs.

In reply comments, Oxy asserted that San Antonio's position that the standard is unnecessary reflects a misunderstanding of the standard's purpose, which is to ensure that congestion costs are in fact assigned directly to those parties responsible for causing the congestion.

Commission response

San Antonio's argument ignores the fact that not all transactions will be represented by bids into the nodal market; congestion rents must also be directly assigned to each scheduled transaction for a resource and load pair, including bilateral transactions that do not participate in the ERCOT-operated energy market and act as price takers for congestion pricing.

CPA and San Antonio have proposed alternative language for nodal pricing for resources and direct assignment of local congestion rents. The commission has added final subsection (e)(2) using language comparable to the CPA language, because the added language expresses the well-established method of implementing direct assignment in a straightforward and common way. However, final subsection (e) leaves open the possibility that other, viable methods of directly assigning all congestion rents to those resources that caused the congestion can be developed, although so far no such methods have been identified.

Comments

AEP and Austin recommended deleting the second sentence in proposed subsection (d)(2). Austin stated that the direct assignment language in the rule would inappropriately limit the range of market-design proposals that stakeholders could consider, and declared that the market design should not be driven by a restrictive definition; rather, the definition should be developed in concert with the market design.

As discussed under Question 2, CenterPoint objected to the alleged arbitrary nature of the concept embodied in the direct assignment language. CenterPoint argued that the treatment of congestion pricing proposed in subsection (d)(2) is troubling, because it replaces a successful ERCOT system, involving the direct assignment of interzonal congestion costs across a CSC to the entities using the constrained path, with a system that is arbitrary in nature.

TXU proposed deleting the direct assignment language. By deleting the direct assignment language, TXU claimed, the commission would avoid unnecessary debate and confusion in creating the Texas Nodal strawman and protocols. TXU additionally stated its belief that the remaining language adequately defines nodal congestion pricing. In reply comments, TXU claimed that retaining the direct assignment language will serve to polarize the Texas nodal development process and prevent ERCOT and market participants from using their practical market knowledge to develop a consensus on a working model. In reply comments, CPA noted that except for Oxy and TIEC, all respondents proposed to delete much or all of the direct assignment language.

TIEC voiced its wholehearted support for the direct assignment language, asserting that the requirements contained therein are fundamental to Texas Nodal and must be included if consumers are to benefit from the new market. TIEC added that direct assignment of congestion costs is critical to provide disincentives for physical and financial withholding. In reply comments, TIEC added that without such assignment, resources can engage in bidding strategies (as with the DEC game) that will penalize loads and will be very difficult to police.

Oxy expressed thoughts nearly identical to those of TIEC with respect to proposed subsection (d)(2). Terming the standard specified in the second sentence an essential element of workable congestion-management and market-mitigation systems, Oxy stated that it works equally well in generation and load pockets. According to Oxy, the necessary and desirable consequence of the proposed standard is to discourage resources from engaging in economic withholding to game the system and artificially increase nodal prices. In reply comments, Oxy reiterated these views, and opined that the proposed standard is consistent with the overall purpose of a nodal system, which is to encourage resources to operate their facilities in a more economically efficient way. Oxy stated in reply comments that it strongly disagrees with TXU's assessment. A lack of commission guidance on such a fundamental goal, Oxy asserted, will lead to more controversy and debate.

Commission response

When approving the current market design in Docket Number 23220, the commission identified the lack of direct assignment of congestion rents on local lines within the ERCOT market as a serious flaw in the wholesale market design, and ordered direct assignment of local congestion rents if local congestion costs reached a $20 million, twelve-month threshold. ERCOT reached that threshold in March 2002. ERCOT stakeholders rejected MOD's proposed implementation of the commission's order, but failed to develop an alternative that met the conditions listed in the order. The commission initiated this rulemaking as a result.

The commission agrees with TIEC in its assertion that the direct assignment requirement is a vital component of the wholesale market design to correct the problems in the current ERCOT wholesale market design. Quoting TIEC, "Nothing will lead to more controversy and debate than a lack of guidance from the commission at the outset as to its fundamental goals."

The commission has been judicious in the amount of detail and in its choice of words in this rule to give ERCOT stakeholders direction in developing a wholesale market design without being overly prescriptive. Nevertheless, the commission agrees with Austin that the direct assignment requirement would limit the number of proposals that stakeholders can consider in designing the ERCOT wholesale market. The commission's intent with the direct assignment requirement in the rule is to address one of the chief problems with the current market design, a consequence of which will limit the options that stakeholders can consider in implementing the rule. Nevertheless, the potential still exists for the stakeholders to identify a number of options to implement the requirements of the rule, some of which could involve substantial leveraging of existing ERCOT systems and therefore may allow for substantially lower implementation costs (e.g., ZEN, a combination of ERCOT staff's simultaneous market clearing (SMC) proposal and MOD's direct assignment proposal, or adapting the current software to use zonal bid curves as proxies for resource nodes). Some of these options might require an aggregation of nodal resource energy prices for the load zones, rather than an aggregation of nodal load energy prices as required in the proposed rule. As a result, the commission has amended the rule (subsection (h) of the final rule) to allow consideration of either type of aggregation. A drawback of using nodal resource energy prices for the load zones is that they would cause some inaccuracies in the zonal load prices. Pursuant to subsection (m) of the final rule, the costs and benefits of using nodal resource energy prices can be evaluated in the cost-benefit analysis and as part of the commission's approval of the protocols to implement the rule.

The commission also acknowledges the concerns that TXU and TIEC expressed that simple language that describes direct assignment may lead to unnecessary debate and confusion. In response, the commission has amended subsection (e) in the final rule to provide stakeholders with "safe harbor" language in paragraph (2). Subsection (e)(2) of the final rule expresses the well-established implementation of direct assignment, without precluding consideration of other options, if they exist. In addition, below, the commission has provided numerical examples to show how direct assignment works in practice, at least with respect to final subsection (e)(2).

The commission strongly disagrees with TXU and Austin that stakeholders should be allowed to address this issue on their own. Although ERCOT stakeholders include a number of people with expertise in engineering, grid operations, and day-to-day marketing of electricity, given the inability of stakeholders to correct some fundamental flaws in the wholesale market design, the commission sees a compelling need to give stakeholders firm direction to ensure that the ERCOT market design and protocols contain key microeconomic principles that are the foundation of a sustainable wholesale electricity market.

Oxy proposed that a generator that engages in economic withholding should somehow be directly assigned congestion costs. Even if Oxy's proposal were feasible, the issue that it raises — local market power abuse through economic withholding — is more properly addressed through final subsection (d) of the rule, which provides for ex-ante mitigated bid curves to address local market power. Under the current market design, a generator whose output is needed to clear congestion has an incentive to avoid scheduling output, because ERCOT pays it only for the incremental output dispatched by ERCOT. This "INC game" does not exist with locational marginal pricing, because the generator is rewarded for relieving the congestion, regardless of whether it self-scheduled its output or ERCOT dispatched it.

Given the importance of direct assignment of local congestion rents as a part of a wholesale market design, the commission rejects requests to eliminate this requirement. The public benefits of direct assignment of congestion rents for all congestion, including local congestion, include better siting decisions by resource developers, reduced gaming opportunities, reduced need to build new transmission lines, and better deployment of advanced demand-side technologies and distributed generation resources. The commission's cost-benefit analysis provides a quantitative estimate of benefits from direct assignment of local congestion rents, and shows that the benefits of direct assignment substantially outweigh its costs.

Comments

Deeming the direct assignment language as too broad, AEP and Reliant stated that a resource may not be in a position to know whether it is the cause of the congestion or whether it is in a position to relieve it. CenterPoint stated that potentially any resource in ERCOT would be in a position to relieve congestion on any constrained interface, but because of differing shift factors, the impact on a constraint of each resource varies.

CenterPoint opined that if commission staff believes that congestion costs must be shifted from loads to resources, proposed subsection (d)(2) should be clarified by adding the adverb "*feasibly* relieve congestion." CenterPoint proposed three further conditions on cost assignment: first, that the "feasibility" be determined by a pre-defined range of resource shift factors on a constraint; second, that resources that could feasibly relieve congestion by lowering output, but do not do so, would be allocated congestion costs; and third, that resources that could feasibly relieve congestion by increasing output, but do not do so, *not* be allocated congestion costs, as such resources have merely foregone an opportunity.

ERCOT noted that many parties have asserted that in some cases local congestion cannot be attributed to specific resources and may result from local configurations. It therefore advocated allowing more flexibility in subsection (d)(2) to allow parties to reach equitable solutions. Specifically, ERCOT suggested allowing itself and the stakeholder process to explore the fairness and workability of various methods for allocating these congestion costs. In addition, ERCOT proposed substituting "costs" for "rents" in subsection (d)(2) and revising the first sentence in (d)(2) to read, "ERCOT shall directly assign all congestion costs to the appropriate entities that caused the congestion."

In reply comments, Oxy objected to the high degree of specificity that some parties advocated, including CenterPoint's suggestion on "feasibility" as related to congestion costs and Reliant's issue of determining whether a resource could but did not relieve congestion, because such determination would also involve deciding whether congestion could be relieved economically. Oxy stated that all of these issues should be worked out in the stakeholder process, and are not necessary in the rule.

Replying to Reliant, Oxy noted that to the extent LaaRs are in a position to relieve congestion and fail to do so, the proposed standard would result in their being assigned congestion costs, just as it would for generators. On the other hand, Oxy stated that it would be inappropriate to specifically assign congestion costs to consumers, *i.e.*, loads not designated as resources.

Commission response

Although an owner of a resource may not know if it is in a position to relieve congestion, the owner can submit a resource-specific bid to help ERCOT relieve congestion, and that bid will effectively produce a cap on the congestion charges that the resource owner will have to pay. The resource owner also can pay congestion rents as a price taker by allowing another resource to clear the congestion on the impacted lines if the resource owner does not wish to alter the scheduled output of the resource in real-time.

Market participants cannot predict the topology of the grid in real-time, because weather, generation outages, and transmission outages impact the topology. The commission acknowledges that direct assignment of local congestion rents will shift the risk of congestion from loads to resources. The commission finds that the problems in the current market design evidence the need for this reallocation of risk to resources.

Furthermore, Dr. Baldick has demonstrated in his studies on zonal dispatch in ERCOT, and as seen in the substantial uplift of OOME Down payments to solve congestion on local lines, that the lack of resource-specific bid curves has been a major inefficiency in the ERCOT market.

Comments

Quoting Dr. Ross Baldick, CPA stated that it is the relationship between the location of the generation and the location of demand, together with the configuration of the transmission system, that determines the congestion; assigning congestion rents only to resources (or only to load) provides incentives that distort production and consumption decisions and also distort siting decisions. Reliant concurred with this assertion, stating that assigning congestion costs only to generators might bias negotiations of bilateral contracts. CenterPoint argued that the rule ignores the fact that load, too, can cause congestion, something that is recognized in today's interzonal congestion-allocation process. CenterPoint recommended adding further specificity by mandating the assignment of costs to resources that can "feasibly" relieve congestion.

In reply comments, Exelon agreed with CPA, including Dr. Baldick's remarks, that the nodal-pricing signals will be a first step in determining where and when capacity should be added and in reducing the building of unnecessary transmission. In response to CenterPoint's opinion that generators build plants where the infrastructure is most conducive, Exelon noted that CenterPoint's former parent company built generation in

New York City because of the nodal-pricing signals, and that new combined-cycle plants are being built in Philadelphia and New York to address the need for energy and capacity made transparent by nodal prices. Exelon added that nodal-pricing signals may also reduce the impact of any future capacity adequacy requirement by providing initial market signals, and that the issue of capacity adequacy must be addressed in conjunction with and as an integral part of the design and development of a Texas nodal market.

Magic Valley, Mid-Tex, and Rayburn stated support in reply comments for ARM's observation (offered in response to Question 4) that congestion is a risk currently borne more efficiently by resources than by load. Unlike load, the three coops asserted, generators have some ability to mitigate or even eliminate the risk of congestion. Therefore, Magic Valley, Mid-Tex, and Rayburn urged the commission, if it proceeds with the rule, not to amend proposed subsection (d)(2) in a way that would shift the risk of congestion to load.

Commission response

The market design prescribed by the rule, specifically final subsection (h) (proposed subsection (d)(5)), requires that loads pay zonal imbalance charges, not nodal imbalance charges. According to his presentation at a workshop in this proceeding on November 1, 2002, Dr. Shmuel Oren noted that generation-node to load-node congestion charges for bilateral transactions are inconsistent with zonal-based imbalance charges for load. Loads at cheap nodes would opt for generation-node to load-node congestion charges, while large loads at expensive nodes and small loads for which real-time metering is not cost-effective would consequently pay higher zonal imbalance charges. As a result, in order to avoid "cherry-picking" of large loads at cheap nodes that might lead to a "death spiral" of increasing prices for small customers, the commission has determined that at this time loads should be settled zonally, not nodally. Nevertheless, load can respond to nodal prices by becoming a LaaR and actively assisting ERCOT in relieving congestion by reducing demand when there is congestion. Another benefit of zonal energy prices for loads is that they greatly facilitate mass market retailing. The commission is concerned that, if load prices were different at each node, it would make it very difficult for retailers to market to residential customers and to offer standard prices, and for residential customers to do price comparisons.

The commission agrees with Dr. Baldick that congestion is caused by load as much as by generators. Nevertheless, as explained above, the commission has made a policy decision to settle load imbalances at zonal prices rather than nodal prices. These zonal prices do reflect locational price differences, albeit on a less granular level. Furthermore, parties to bilateral transactions are free to reallocate the risk of nodal congestion rents from resources to loads. In addition, as indicated above, loads that are willing to be dispatched (curtailed) by ERCOT to relieve congestion can become LaaRs and be treated as a resource (i.e., be subject to nodal prices when dispatched).

Settling resource imbalances at nodal prices and load imbalances at zonal prices is a well established practice. All three of the currently operational nodal markets in the United

States (i.e., PJM, New York, and New England) effectively use this approach. Although PJM calculates nodal prices for loads, loads are in practice settled at zonal prices pursuant to state public utility commission directive.

The commission disagrees with Reliant's contention that the direct assignment language would create significant adverse impacts on the negotiation of bilateral contracts. As the commission stated above, the buyers and sellers can allocate the congestion rents among themselves in a competitive market, and will have the ability to hedge congestion rents through the purchase of congestion revenue rights.

Comments

Reliant also recommended correcting a perceived misapplication of the term "imbalance charges" and replacing "rents" with "costs," because resources are making payments rather than receiving them. Specifically, Reliant's proposed revision would delete the first two sentences and substitute the following for the third sentence in subsection (d)(2): "Congestion *costs* shall be consistent with the nodal prices used to financially settle resource imbalance charges and the zonal load aggregation prices used to financially settle load imbalance charges."

Commission response

The commission disagrees with the suggestion by CPA, Reliant, and ERCOT to substitute the term "congestion costs" for the term "congestion rents." The concept being applied in final subsection (e) (proposed subsection (d)(2)) effectively is pricing a scarce resource, transmission capacity, not the concept of minimization of cost.

The commission disagrees with Reliant that rents imply just a collection of revenues. A rent is the price of a scarce resource. When there is no congestion on the ERCOT grid, the rent on the line is zero, because the resource is not scarce (i.e., the marginal cost of using an additional increment of the grid is zero).

The commission provides the following numerical examples to show how congestion rents will be directly assigned and load and resource imbalances settled in the ERCOT market pursuant to subsection (e)(2) of the final rule.

Figure 2: 16 TAC Chapter 25 - Preamble

Assumptions
• Security-constrained, economic dispatch (SCED) sets prices for individual resource and load nodes (from subsections (f) and (h) of the final rule). • Individual load node prices aggregated into zonal prices for settling load imbalances and assigning congestion rents (from subsections (e) and (h) of the final rule). • Resource A has a capacity of 1,400 MW and bids at $20 / MWh. • Resource B has a capacity of 500 MW and bids at $30 / MWh. • Resource C has a capacity of 200 MW and bids at $20 / MWh. • Load D is 800 MW, and can arrange bilateral contracts with resources A, B, and C, as well as buy from the ERCOT spot (real-time) market. • Load E is 800 MW, and can arrange bilateral contracts with resources A, B, and C, as well as buy from the ERCOT spot (real-time) market. • Resource A and load D are separated from resources B and C and load E by a transmission line with transfer capability of 1,000 MW. • Resource A: o Cases I and II: resource A has bilateral contracts with load D and load E of 800 MW and 300 MW, respectively. Resource A offers 300 MW of INC bids for real-time dispatch. o Case III: resource A has bilateral contracts with load D and load E of 800 MW and 500 MW, respectively. Resource A offers 100 MW of INC bids for real-time dispatch. • Resource B has no bilateral contract and offers 500 MW of INC bids for real-time dispatch. • Resource C has a bilateral contract of 200 MW with load E and offers no INC bids for real-time dispatch.

Case I: No Congestion
Transmission line can transfer 1,000 MW. Under SCED: Resource A generates 1,100 MW to meet bilateral contracts, sells 300 MW in spot market. Resource C generates 200 MW to meet bilateral contracts.
Zonal load price = $20/MWh (load D and load E both at $20) Congestion rents = none to assign
Resource Imbalance Payments (Sales to ERCOT in spot market): Output from spot sale * nodal resource price = 300 MW * –$20 = –$6,000 Resource A receives $6,000 in resource imbalance payments from ERCOT.
Load Imbalance Charges (ERCOT sells power to load E in spot market): Purchases from Resources A, B, and C * zonal load price = (300 MW + 0 MW + 0 MW) * $20 = $6,000 Load E pays ERCOT $6,000 in load imbalance charges.
Net Position of ERCOT Congestion charges $ 0 Resource imbalance charges –$6,000 Load imbalance charges $ 6,000 ERCOT net position $ 0

Case II: Congestion
Because of a change in the grid topology, ERCOT reduces the transfer limit on the transmission line from 1,000 MW to 500 MW
Under SCED: Resource A generation: 1,100 MW to meet bilateral contracts, 200 MW into spot market. Resource B generation: 100 MW into spot market. Resource C generation: 200 MW to meet bilateral contracts. Zonal load price = $25/MWh (load D at $20 and load E at $30)
Congestion charges, congestion credits, and spot market transactions: <u>Resource A:</u> *Congestion associated with bilateral contracts:* Output related to bilateral contracts * (zonal load price – nodal resource price) = 1,100 MW * ($25 – $20) = $5,500 Resource A pays $5,500 in congestion charges to ERCOT. *Resource Imbalance Payments (Sales to ERCOT in spot market):* Output from spot sale * nodal resource price = 200 MW * –$20 = –$4,000 Resource A receives $4,000 in resource imbalance payments from ERCOT. <u>Resource B</u> *Resource Imbalance Payments (Sales to ERCOT in spot market):* Output from spot sale * nodal resource price = 100 MW * –$30 = –$3,000 Resource B receives $3,000 in resource imbalance payments from ERCOT.

Resource C

Congestion associated with bilateral contracts:

Output related to bilateral contract * (zonal load price – nodal resource price)

= 200 MW * ($25 – $30)

= –$1,000

Resource C receives $1,000 in congestion credits from ERCOT.

ERCOT

Load Imbalance Charges (ERCOT sells power to Load E in spot market):

Purchases from resources A, B, and C * zonal load price

= (200 MW + 100 MW + 0 MW) * $25

= $7,500

Load E pays ERCOT $7,500 in load imbalance charges.

Net Position of ERCOT

Congestion charges	$4,500
Resource imbalance charges	–$7,000
Load imbalance charges	$7,500
ERCOT net position	$5,000

ERCOT has received $5,000 in net revenues from transactions, and distributes the proceeds according to commission rules or ERCOT protocols.

Shadow price of congested line:

= $5,000 of revenue / 500 MW of transmission line

= $10

Case III: Congestion
Because of a change in the grid topology, ERCOT reduces the transfer limit on the transmission line from 1,000 MW to 500 MW. Congestion causes use of resource B.
Under SCED: Resource A generates 1,300 MW to meet bilateral contracts. Resource B generates 100 MW into spot market. Resource C generates 200 MW to meet bilateral contracts. Zonal load price = $25/MWh (load D at $20 and load E at $30)
Congestion charges, congestion credits, and spot market transactions <u>Resource A</u> *Congestion associated with bilateral contracts:* Output related to bilateral contracts * (zonal load price – nodal resource price) = 1,300 MW * ($25 – $20) = $6,500 Resource A pays $6,500 in congestion charges to ERCOT. <u>Resource B</u> *Resource Imbalance Payments (Sales to ERCOT in spot market):* Output from spot sale * nodal resource price = 100 MW * –$30 = –$3,000 Resource B receives $3,000 in resource imbalance payments from ERCOT. <u>Resource C</u> *Congestion associated with bilateral contracts:* Output related to bilateral contract * (zonal load price – nodal resource price) = 200 MW * ($25 – $30) = –$1,000 Resource C receives $1,000 in congestion credits from ERCOT.

<u>ERCOT</u> *Load Imbalance Charges (ERCOT sells power to Load E in spot market):* Purchases from resources A, B, and C * zonal load price = (0 MW + 100 MW + 0 MW) * $25 = $2,500 Load E pays ERCOT $2,500 in load imbalance charges.
<u>Net Position of ERCOT</u> Congestion charges $5,500 Resource imbalance charges –$3,000 Load imbalance charges <u>$2,500</u> ERCOT net position $5,000
ERCOT has received $5,000 in net revenues from transactions, and distributes the proceeds according to commission rules or ERCOT protocols.
Shadow price of congested line: = $5,000 of revenue / 500 MW of transmission line = $10

Comments

OPC noted that even with the cost of congestion uplifted to load on a zonal basis, there would be winners and losers; depending on the size and coverage of zones, loads would see an increase or decrease in costs, and businesses may see a change in their production costs. OPC pointed out that while the analysis in the rule's introduction predicted declining overall costs and a more efficiently functioning market, this result would not hold for everyone. OPC encouraged the commission to find ways of mitigating zonal congestion costs, perhaps by allocating congestion rights to load and allowing proceeds from congestion right auctions to lower congestion costs within a zone.

In reply comments, Reliant took issue with the suggestion of LCRA, ARM, and OPC that the current congestion zones should be preserved in the new nodal market. Reliant asserted that the nodal model will render useless the current congestion zones and accompanying CSCs. Moreover, Reliant contended, imposing an administrative construct like CSCs when a more rigorous nodal solution is available makes no sense. Reliant argued that the former approach inhibits the ability to solve and hedge local congestion costs, and contributes to the problem of ERCOT-wide uplift of such costs. In addition, it mutes price signals for generation siting and load-procurement decisions. Reliant reiterated its recommendation to allocate local congestion costs on a zonal basis until the nodal model can be implemented.

In reply to Reliant's last point, Magic Valley, Mid-Tex, and Rayburn noted that moving immediately to a zonal-uplift regime will not reduce non-CSC costs, but will merely require them to be paid by a smaller group of customers.

Commission response

The commission agrees with OPC that interzonal price differentials are a significant issue, and great care will need to be taken to balance the competing goals of sending price signals to loads and avoiding inequitable cost shifting given that most loads, due currently to the relatively high cost of advanced meters, have little practical ability to respond to short-term price signals. As discussed above with respect to question 3, the commission considers the zones ultimately chosen by ERCOT to be a major issue, and will consequently review ERCOT's selection of zones carefully when it approves the ERCOT protocols that implement this rule.

Comments

STEC also proposed considering the treatment of entities that have built generation and transmission prior to competition to serve their customers but are given OOME Down instructions. STEC stated that the elimination of OOME Down payments could be devastating to these entities. STEC agreed that these entities should not make a profit when complying with OOME Down instructions, but that they should be made whole so their customers do not suffer.

Commission response

Compensation of all generators that are required to decrease their scheduled output is what creates the opportunity for playing the DEC game, described above. In addition, such payments dampen locational price signals for resources, and consequently fail to send an adequate price signal for the location of new resources, and inappropriately socialize the risk of congestion to loads rather than to the resources that cause the congestion. Nevertheless, congestion revenue rights, which ERCOT is required to provide pursuant to subsection (i) of the final rule (subsection (d)(6) of the proposed rule), can be used by market participants such as those described by STEC to hedge the cost of congestion.

The market design required by the rule will provide market participants such as STEC with benefits and alternatives that can reduce the impact of lost OOME Down payments. First, STEC will save money because OOME Down payments made to other market participants will no longer be uplifted to STEC on a load-ratio-share basis. Second, the projected reduction in transmission construction under Texas Nodal will reduce the amount of postage-stamp transmission service payments that STEC will make in the future. Third, STEC has the ability to request upgrades to the transmission grid in such a way as to eliminate the congestion that concerns it, although there of course is a limit to the amount of transmission upgrades that can be cost-effectively built. Fourth, as explained above, congestion rights can be used to hedge the cost of congestion.

Proposed Subsection (d)(3); Final Subsection (f)

Comments

TEC stated that the consensus of its member coops is that they would prefer for ERCOT's current zonal model to remain in place until such time as they are confident that replacing it will not jeopardize their ability to participate in the market. TEC's member coops, being risk-averse, prefer taking incremental steps as the market matures, TEC noted.

Commission response

The commission addresses this issue in its responses to comments on the commission's cost-benefit analysis. As explained there, the costs and risks of continued use of the current market design substantially exceed the costs and risks of changing to the market design required by the rule.

Comments

Magic Valley, Mid-Tex, and Rayburn offered extensive comments highlighting what they consider to be the drawbacks of a nodal-pricing system. They particularly criticized the proposed market design for relying on short-term price signals to induce long-term remedies to congestion. The commission's assumption that transmission facilities have not been optimally sited because of inappropriate price signals, Magic Valley, Mid-Tex, and Rayburn argued, does not recognize the many other factors (such as local opposition and environmental limitations) that may prevent the construction of needed generation and transmission facilities.

Commission response

As the commission notes above in connection with subsection (a), nodal pricing of resources encourages improved dispatch of resources in real-time. Also, the current zonal model, though inadequate, also sends some short-term prices signals as well.

The commission disagrees with Magic Valley, Mid-Tex, and Rayburn that nodal pricing of resources sends appropriate signals only in the short run. Persistent differences in prices across the grid in a Texas nodal model will encourage resources to site more optimally than under the current zonal model and better highlight when transmission is the optimal solution to local congestion. In many cases under the current zonal model, transmission construction is the only long-term remedy available.

The commission also notes that the environmental factors Magic Valley, Mid-Tex, and Rayburn cite are not relevant for wind resources and will actually encourage the development of demand-side resources (including LaaRs) and clean distributed resources such as fuel cells. Nodal pricing for resources is very important for the optimal development of these resources, which in turn will reduce the amount of transmission construction within ERCOT.

Comments

Magic Valley, Mid-Tex, and Rayburn also criticized locational marginal pricing on equity grounds. In some cases, they observed, the consumers who must pay high nodal prices did not cause the congestion, but were victimized by congestion caused by other factors, such as a generation or transmission failure in another area. Moreover, they noted that consumers in areas initially under-served with transmission capacity will be penalized for decisions made not by themselves, but by others under an earlier paradigm, when generation and transmission facilities were built by vertically integrated utilities to serve load in a single control area on a least-cost basis. In reply comments, Magic Valley, Mid-Tex, and Rayburn went even further, declaring that implementing a nodal market will simply penalize some market participants and reward others based on siting decisions made years ago by parties operating in a completely different environment.

OPC stated in reply comments that it agrees with Magic Valley, Mid-Tex, and Rayburn that short-term price signals are not the best inducement for long-term investment. OPC remarked that although LMP may improve generation siting, additional transmission facilities will be needed to address large portions of ERCOT's congestion problems. In addition, OPC indicated that it shares the concerns of Magic Valley, Mid-Tex, and Rayburn with respect to equity, and asserted that the possibility such concerns raise as to costs and benefits begs the need for modeling the effects of LMP.

Magic Valley, Mid-Tex, and Rayburn questioned whether the proposed rule accords sufficient importance to long-term transmission planning. They warned that if transmission projects, which require long lead times, are not planned and undertaken in anticipation of future needs, rural areas and small communities could be strangled by diminished access to reasonably priced energy.

Commission response

As noted in connection with Questions 2 and 3 above, the commission is aware of potential problems associated with load pockets, including those that have arisen as part of the historical legacy of transmission planning and generation siting prior to deregulation of ERCOT wholesale and retail markets. The commission reiterates that the concerns expressed by OPC, Magic Valley, Mid-Tex, and Rayburn can be addressed through the ongoing transmission planning process at ERCOT and the commission, local market power mitigation, which will be addressed by the commission in Project Number 27917, and the configuration of load zones for settling load imbalance charges.

Comments

Reliant recommended deleting the reference "for resources" in the second sentence of subsection (d)(3). Without this deletion, Reliant stated, resource nodal prices would appear to be security-constrained, whereas the "load node prices" mentioned in subsection (d)(5) would not.

Commission response

The commission disagrees with Reliant's comments. Resources must be dispatched consistent with security constraints, whereas the lode node prices result from the resource dispatch.

The commission amends the language in this subsection to include the phrase "locational marginal prices, consistent with subsection (e)" to clarify the intent of this subsection and to make the language in this subsection consistent with the language in subsection (e) of the final rule.

Comments

In reply comments, CPA strongly opposed the implication by several stakeholders that only repairs to the current market are needed. CPA asserted that the underlying problem — that ERCOT does not know which units will be dispatched and when — will not be a problem under a nodal system that complies with the principles set forth in the rule.

STEC stated that it appreciates the directive that nodal prices for resources are to be based on security-constrained, economic dispatch, as this requirement should ensure that the most economical resources would be used to generate power. STEC cautioned that entities given OOME Down instructions must be made whole, however. Eliminating

OOME Down payments will adversely affect municipally owned utilities (MOUs) and coops, STEC explained, because when they are asked to reduce production at a unit they may be forced to purchase power from the market at a much higher cost. Furthermore, STEC reported, output levels in some plants cannot be reduced to zero in response to OOME instructions. Denton/Garland voiced a similar concern regarding NOIEs with captive generation. As a partial remedy to these problems, STEC recommended that the commission clarify when adopting the rule that the preassigned congestion rights allocated to MOUs and coops will be honored under the new nodal system and can be used to address both local and zonal congestion.

Commission response

STEC's comments about OOME Down payments are addressed above with respect to final subsection (e) (proposed subsection (e)(2)). The rule does not address the extent to which congestion rights should be allocated/preassigned to NOIEs. The commission intends to address this issue in a follow-up rulemaking.

Proposed Subsection (d)(4); Final Subsection (g)

Comments

Reliant asserted that it is unnecessary to specify the details for forming trading hubs, but that the rule should indicate the importance of ERCOT's systems being able to support the market's information requirements when hubs are formed.

Commission response

The commission disagrees with Reliant's proposal. Reliant's proposal would not make it clear that ERCOT must calculate trading hub spot prices.

Proposed Subsection (d)(5); Final Subsection (h)

Comments

As indicated above under final subsection (f) (proposed subsection (d)(3)), Reliant suggested modifying subsection (d)(5) by substituting "nodal energy prices" for "load node prices." It also suggested referring to "load aggregations" to avoid confusion with the existing congestion-management system.

Commission response

The commission disagrees with Reliant's suggestion. The term "zone" is a term of art in the electric industry and is not used just to refer to a particular type of congestion management. "Zone" is an effective way to characterize the load prices prescribed by the rule.

Comments

Although it did not recommend any changes to proposed subsection (d)(5), San Antonio reported that some market participants believe that the intent of this provision is to retain the current (or similar) load zones. San Antonio disputed this intent, and averred that such an outcome would be unacceptable as the wholesale market adopts more granular, transparent, and marginal-cost-based pricing mechanisms. The adoption of a few large zones, it maintained, would lead to considerable socialization of congestion costs, in conflict with the commission's clearly articulated policy and efficiency goals. San Antonio added that it interprets proposed subsection (d)(5) to indicate that the number and location of any load zones in the future market design is an open question, to be considered through the stakeholder process. In reply comments, CPA expressed agreement with this view.

CPA encouraged the commission to promote flexibility in the definition and formation of load zones by allowing, for example, the determination of a separate LMP for an aggregate of nodes within a load zone if an entity is willing and able to meet the technical requirements for metering and settlements. CPA stated that it would defer to the collective knowledge of the consumer sector and the LSEs in determining the appropriate transitional treatment for load pricing in the initial stages of the Texas nodal implementation. It added that with more nodal-market experience, stakeholders may determine that additional levels of granularity in the definition of load zones are appropriate for settlements.

CPA in reply comments agreed with ARM that once a zone is established it should remain for commercial purposes, but maintained that such retention should not impede ERCOT's ability to define different aggregations of nodes when requested to do so by market participants.

Commission response

The commission confirms San Antonio's comments that subsection (h) in the final rule (subsection (d)(5) in the proposed rule) is not intended to require that the current or similar load zones be maintained. The current zones were established based on what were determined to be commercially significant constraints and are subject to change on an annual basis under the current protocols, with only congestion rents associated with those constraints being directly assigned. Under the market design prescribed by the rule, which requires that all congestion rents be directly assigned, the location of commercially significant constraints need not be the overriding factor in the determination of zones. Among other possible factors in establishing the zones, the commission expects ERCOT and its stakeholders to balance the need for large zones to facilitate mass market competitive retailing with the potential for cross-subsidies amongst loads that result from zonal aggregations.

As discussed above with respect to final subsection (e) (proposed subsection (d)(2)), the commission has amended final subsection (h) (proposed subsection (d)(5)) to allow consideration of nodal resource energy prices to develop zonal load energy prices for settling imbalances and assigning congestion rents. In addition, the commission amends the language in this final subsection (h) to include the phrase "locational marginal prices, consistent with subsection (e)" to clarify the intent of this subsection and to make the language in this subsection consistent with the language in subsection (e) of the final rule.

Proposed Subsection (d)(6); Final Subsection (i)

Comments

Reliant claimed that there is no need for the commission to adopt the existing allocation of PCRs in a new congestion-management system. Accordingly, Reliant recommended deleting from the second sentence of subsection (d)(6) the language, "except as otherwise ordered by the commission for any preassigned CRRs approved by the commission;" the modified sentence would state, "ERCOT shall auction all CRRs, using a simultaneous combinatorial auction."

Magic Valley, Mid-Tex, and Rayburn recommended that the commission exploit the broad leeway given by proposed subsection (d)(6) to preassign CRRs, in order to protect customers' existing usage of the electric grid. In addition, they advocated allowing LSEs and other wholesale customers to obtain CRRs for terms long enough to hedge the transmission service that they will need to continue shifting their power supplies to their loads, and allowing CRRs to be appropriately adjusted when the termination of a contract requires an LSE to shift power supplies.

In reply comments, Magic Valley, Mid-Tex, and Rayburn strongly opposed Reliant's suggestion that all CRRs should be auctioned. The three coops reiterated their view that reserving sufficient CRRs for LSEs is critical for the economic well-being of rural areas served by coops. They asserted that auctions would allow parties with strategic generation portfolios to exercise market power and to exploit their greater knowledge about the historical incidence of congestion to accurately value CRRs.

In reply comments, CPA stated that it agrees with Magic Valley, Mid-Tex, and Rayburn that it is appropriate for the commission to preassign CRRs under certain circumstances, namely when the entity has long-term contractual commitments entered into before September 1, 1999 for annual capacity and energy from a particular remote generation resource. CPA also stated that transmission rights should be re-configurable to provide price certainty between any nodes, load aggregates, or zone aggregates used by market participants.

In reply comments, OPC stated that it shares Magic Valley, Mid-Tex, and Rayburn's support for allocating CRRs to LSEs. In OPC's view, this method could mitigate some of the equity issues faced by customers in load pockets.

Although they were not expressly addressing proposed subsection (d)(6), Magic Valley, Mid-Tex, and Rayburn suggested that providing transmission credits could mitigate the harm to customers in load pockets resulting from a move to a nodal-pricing system. Alternatively, they noted, the commission could allocate CRRs in a manner that ensures that such customers would receive sufficient CRRs to provide a complete hedge against increased congestion charges. In addition, Magic Valley, Mid-Tex, and Rayburn urged the commission to consider delaying the implementation of the rule until enough generation and transmission infrastructure can be added to allow customers in load pockets to have real competition for their loads.

In reply to Magic Valley, Mid-Tex, and Rayburn, TIEC stated that CRRs should not be preassigned to LSEs or REPs, but to loads themselves. TIEC acknowledged that the relationship of MOUs and coops with their customers may be direct enough for those LSEs to provide this function, but said that such is not the case for REPs dealing with retail competition. In the latter case, TIEC continued, allocating CRRs to anyone other than the customers would give an existing supplier with preassigned CRRs potential leverage over a customer and enable the supplier to extract rents from that customer. TIEC urged the commission to clarify that the entitlements of an end-use customer to allocated CRRs or the associated revenues from a CRR auction are independent of any REP that the customer may select.

Commission response

Subsection (i) in the final rule (subsection (d)(6) of the proposed rule) does not specify the extent to which CRRs should be preassigned; it only requires that preassigned (allocated) CRRs be approved by the commission. Likewise, the paragraph does not specify the terms of the CRRs or the allocation of CRR auction proceeds. The commission intends to conduct to address CRRs with more specificity in Project Number 28226, *Rulemaking Proceeding on Congestion Rights in the Electric Reliability Council under a Nodal Market Design*.

Proposed Subsection (d)(7); Final Subsection (j)

Comments

ERCOT proposed new language for this subsection to stress the commission's key role in developing market-mitigation measures. ERCOT's suggested provision reads as follows: "The commission shall develop market power mitigation measures. At the direction of the commission, ERCOT shall apply market power mitigation methods to energy and ancillary capacity services that it procures."

Bryan stated that the commission should address market-power abuses and how those would be mitigated in the new market design.

Reliant stated that it understood the market-power mitigation in this provision to refer only to local market power, which should be addressed in developing a nodal system. Because Reliant expects ancillary services to continue to be procured on an ERCOT-wide basis or self-arranged in the day-ahead period, Reliant reasoned, there is no need to address local market power for ancillary services. Reliant therefore recommended deleting the phrase "and ancillary capacity services" from subsection (d)(7).

Commission response

The commission agrees with ERCOT that it is important for the commission to address potential market power abuse and other forms of market failure. Consequently, the commission intends to conduct a follow-up rulemaking on this issue in Project Number 27917, *Rulemaking on Pricing Safeguards for ERCOT-Operated Wholesale Markets*. Nevertheless, the commission will not be able to address through its rulemakings all possible market failures, and consequently ERCOT remains obligated to address market failure to the extent that market failure is not addressed by the commission. The commission has clarified this subsection accordingly.

Comments

Magic Valley, Mid-Tex, and Rayburn declared that the rule should state a commitment to maintaining a comprehensive and fully empowered market-power-mitigation protocol. The need for comprehensive mitigation is particularly critical in an LMP environment, the three coops stated, because price spikes could have devastating consequences for a relatively small portion of Texas customers. Noting that certain other regional transmission organizations (RTOs) have an RTO-specific institution charged with overseeing market-participant behavior, Magic Valley, Mid-Tex, and Rayburn recommended that the commission ensure that the resources assigned the market-power-mitigation task are adequate to ensure success. Magic Valley, Mid-Tex, and Rayburn further stated that the market monitor should conduct a detailed structural analysis of the regional market and its sellers. Only sellers without market power should be allowed to sell at market-based rates, the three coops opined; those with market power should be required to comply with mitigation measures, such as unit-specific bid caps.

In its reply comments, OPC strongly endorsed Magic Valley, Mid-Tex, and Rayburn's recommendations relating to market-power mitigation. OPC opined that the rule should state the commission's willingness to pursue ex-post mitigation as needed, in addition to ex-ante mitigation.

In reply comments, CPA said that they share the concern of LCRA and Oxy that improper market development could pave the way for market manipulation, but disputed the assertion (in response to Question 3) that nodally priced systems are much more susceptible to gaming than are other systems. Rather, CPA averred, market power is simply more easily detected in a nodal system, because of price transparency.

Magic Valley, Mid-Tex, and Rayburn expressed the additional concern that the proposed rule provides for insufficient remedies for parties exercising market power. Believing that ex ante mitigation measures may limit ERCOT to mitigating only previously proscribed activities, the three coops urged the commission to require that market rules prohibit any activity that creates or worsens shortages or constraints, or that falsely conveys the impression of shortages or constraints. Magic Valley, Mid-Tex, and Rayburn further stated that the market monitor should have the authority to order offending participants to temporarily cease and desist. Moreover, they asserted, the penalties for infractions should be sufficiently severe in order to deter such misbehavior.

Asserting that the appropriateness of various market-power-mitigation measures depends on the electrical characteristics of a region's power system and on the market design itself, CPA maintained that it is impossible to suggest specific mitigation measures before knowing the details of the future market design.

Commission response

The commission agrees that the policing of market participant behavior is critical to the success of a competitive electricity market. As explained above, the commission has initiated a rulemaking, Project Number 27917, to address pricing protections for ERCOT-operated wholesale markets. In addition, the commission has initiated another related rulemaking, Project Number 26201, *Rulemaking on Enforcement of Wholesale Market Rules*. Furthermore, the commission has a Market Oversight Division that functions as the market monitoring unit (MMU) for ERCOT in a manner similar to MMUs within regional transmission organizations and independent system operators in other regions of the country.

Proposed Subsection (d)(8); Final Subsection (k)

Comments

Though not proposing any changes to the body of proposed subsection (d)(8), Reliant questioned whether this and following provisions should be renumbered as new subsections (not in subsection (d)), as they apply not just to the development of a nodal system, but to the overall ERCOT market.

Commission response

The commission addresses the organization of the rule as part of its response to comments on subsection (e).

Proposed Subsection (d)(9); Final Subsection (l)

Comments

To align the language in this provision with that in the protocols regarding ERCOT's determination of ancillary-service prices, Reliant suggested replacing the word "set" with "determine" in subsection (d)(9).

Commission response

The commission declines to make this non-substantive change, because it believes that the word "set" better conveys the fact that the resulting market clearing price will be used for financial settlement.

Proposed Subsection (e); Final Subsection (m)

Comments

AEP proposed that the language in this subsection be changed to allow for the Texas nodal system to be designed and ready to implement ahead of schedule.

Austin suggested that there should be flexibility in the timeline to account for unforeseen circumstances that might require an extension beyond the March 1, 2006 deadline. San Antonio, Bryan, ARM, Denton/Garland, Cap Rock, CenterPoint, and TXU agreed, and commented on the complexity of the project and the need for market testing, citing the current market's implementation problems as supporting the need for flexibility in the timeline.

ERCOT submitted changes to proposed subsection (e) reflecting its preference that the protocols implementing the requirements in subsection (d) be developed through the normal protocols-revision processes by July 1, 2004. Commenting that it prefers for progress to be seen in terms of milestones and not dates, ERCOT also proposed language stating that should ERCOT determine that the implementation date of March 1, 2006 is not feasible, it will report such determination to the commission and suggest an anticipated implementation date.

TXU recommended that the March 1, 2006 date be changed to reflect the implementation occurring after the price-to-beat period ends. ARM, Cap Rock, Bryan, and Denton/Garland supported the same position, fearing that all REPs, both competitive and affiliated, would suffer should implementation ahead of the price-to-beat expiration diminish headroom.

Commission response

Consistent with the discussion above in connection with question 1 and in response to stakeholder comments on this subsection and in the preamble questions, the commission has extended the deadlines to ensure that ERCOT and its stakeholders have sufficient time to design the Texas nodal market, convert the design into protocol language, and develop and test the software and systems before implementation of the market. As to the concerns about meeting the rule deadlines, the commission believes that it has provided adequate time to meet the deadlines. Furthermore, the commission expects ERCOT and its stakeholders to work diligently to meet the deadlines in the rule and believes that the deadlines are necessary to help ensure such diligence.

As discussed above in connection with question 2, the commission has amended subsection (m) of the final rule to require ERCOT to use a stakeholder process to develop a wholesale market design that complies with the rule.

As explained above in the discussion concerning question 5, the market model that ERCOT implements in response to this rule must comply with the specific elements prescribed by this rule. To make this clear, the commission has converted the paragraphs in proposed subsection (d) to separate subsections.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other clarifications and minor modifications for the purpose of clarifying its intent.

This new section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2003) (PURA), which provides the commission with the authority to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; §35.004(e), which requires that the commission ensure that ancillary services necessary to facilitate the transmission of electric energy are available at reasonable prices with terms and conditions that are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive; §39.001(d), which requires the commission to order competitive rather than regulatory methods to achieve the goals of PURA Chapter 39 to the greatest extent feasible; §39.151(a)(1), which requires that ERCOT ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; §39.151(a)(2), which requires that ERCOT ensure the reliability and adequacy of the regional electrical network; §39.151(a)(4), which requires that ERCOT ensure that electricity production and delivery are accurately accounted for among generators and wholesale buyers in the ERCOT power region; §39.151(c), under which the commission certified ERCOT to perform the functions prescribed by §39.151 for the ERCOT power region; §39.151(d), which requires ERCOT to establish and enforce procedures, consistent with PURA and the commission's rules, relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants, and which makes these ERCOT procedures subject to commission oversight and review; §39.151(i), which permits the commission to delegate authority to ERCOT to enforce operating standards within the ERCOT regional electrical network and to establish and oversee transaction settlement procedures, and which permits the commission to establish the terms and conditions for ERCOT's authority to oversee utility dispatch functions after the introduction of customer choice; and §39.151(j), which requires a retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, or power generation company to observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by ERCOT.

Cross Reference to Statutes: PURA §§14.002, 35.004(e), 39.001(d), and 39.151.

§25.501. Wholesale Market Design for the Electric Reliability Council of Texas.

(a) **General.** The protocols and other rules and requirements of the Electric Reliability Council of Texas (ERCOT) that implement this section shall be developed with consideration of microeconomic principles and shall promote economic efficiency in the production and consumption of electricity; support wholesale and retail competition; support the reliability of electric service; and reflect the physical realities of the ERCOT electric system. Except as otherwise directed by the commission, ERCOT shall determine the market clearing prices of energy and other ancillary services that it procures through auctions and the congestion rents that it charges or credits, using economic concepts and principles such as: shadow price of a constraint, marginal cost pricing, and maximizing the sum of consumer and producer surplus.

(b) **Bilateral markets and default provision of energy and ancillary capacity services.** ERCOT shall permit market participants to self-arrange (self-schedule or bilaterally contract for) energy and ancillary capacity services, except to the extent that doing so would adversely impact ERCOT's ability to maintain reliability. To the extent that a market participant does not self-arrange the energy and ancillary capacity services necessary to meet its obligations or to the extent that ERCOT determines that the market participant's self-arranged ancillary services will not be delivered, ERCOT shall procure energy and ancillary capacity services on behalf of the market participant to cover the shortfall and charge the market participant for the services provided.

(c) **Day-ahead energy market**. ERCOT shall operate a voluntary day-ahead energy market, either directly or through contract.

(d) **Adequacy of operational information.** ERCOT shall require resource-specific bid curves for energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, and ERCOT shall use these bid curves or ex-ante mitigated bid curves to address market failure, as appropriate, in its operational decisions and financial settlements.

(e) **Congestion pricing.**

(1) ERCOT shall directly assign all congestion rents to those resources that caused the congestion.

(2) ERCOT shall be considered to have complied with paragraph (1) of this subsection if it complies with this paragraph. ERCOT shall settle each resource imbalance at its nodal locational marginal price (LMP) calculated pursuant to subsection (f) of this section; each load imbalance at its zonal

price calculated pursuant to subsection (h) of this section; and congestion rents on each scheduled transaction for a resource and load pair at the difference between the nodal LMP at the resource injection location calculated pursuant to subsection (f) of this section and the zonal price at the load withdrawal location calculated pursuant to subsection (h) of this section.

(f) **Nodal energy prices for resources.** ERCOT shall use nodal energy prices for resources. Nodal energy prices for resources shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch.

(g) **Energy trading hubs.** ERCOT shall provide information for energy trading hubs by aggregating nodes and calculating an average price for each aggregation, for each financial settlement interval.

(h) **Zonal energy prices for loads.** ERCOT shall use zonal energy prices for loads that consist of an aggregation of either the individual load node energy prices within each zone or the individual resource node energy prices within each zone. Individual load node or resource node energy prices shall be the locational marginal prices, consistent with subsection (e) of this section, resulting from security-constrained, economic dispatch. ERCOT shall maintain stable zones and shall notify market participants in advance of zonal boundary changes in order that the market participants will have an appropriate amount of time to adjust to the changes.

(i) **Congestion rights**. ERCOT shall provide congestion revenue rights (CRRs), but shall not provide physical transmission rights. ERCOT shall auction all CRRs, using a simultaneous combinatorial auction, except as otherwise ordered by the commission for any preassigned CRRs approved by the commission. CRRs shall not be subject to "use-it-or-lose-it" or "schedule-it-or-lose-it" restrictions and shall be tradable.

(j) **Pricing safeguards**. ERCOT shall apply pricing safeguards to protect against market failure, including market power abuse, consistent with direction provided by the commission.

(k) **Simultaneous optimization of ancillary capacity services**. For ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall use simultaneous optimization and shall set prices for each service to the corresponding shadow price.

(l) **Multi-settlement system for procuring energy and ancillary capacity services**. For any energy and ancillary capacity services that it competitively procures in the day-ahead or operating day, ERCOT shall set a separate market clearing price for each procurement of a particular service.

(m) **Development and implementation.** ERCOT shall use a stakeholder process to develop a wholesale market design that complies with this section. ERCOT shall file with the commission an application for approval of protocols that comply with this section and for approval of energy load zones that comply with subsection (h) of this section. As part of this application, ERCOT shall include an independent cost-benefit analysis of options that would comply with this section. These options may include an option, or options, that would involve modification of the existing ERCOT wholesale market design. However, all options that are evaluated in the cost-benefit analysis shall comply with this section. For each of the options, the cost-benefit analysis shall include the estimated net benefits of the option in comparison to the current market design. If the independent cost-benefit analysis produces a negative result, the stakeholder process shall continue until a wholesale market design is produced that yields a positive result upon application of the cost-benefit analysis. The protocols and all cost-benefit analyses shall be filed by ERCOT by November 1, 2004. The cost-benefit analysis shall be prepared with sufficient detail to provide the stakeholders and the commission with the necessary information to modify or delete specific items or categories of expenses in the event the costs exceed the benefits. ERCOT shall fully implement the requirements of this section by October 1, 2006.

This agency hereby certifies that the rule, as adopted, 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 §25.501, relating to Wholesale Market Design for the Electric Reliability Council of Texas, is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 22nd DAY OF SEPTEMBER 2003.

PUBLIC UTILITY COMMISSION OF TEXAS

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Rebecca Klein, Chairman

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Brett A. Perlman, Commissioner

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Julie Parsley, Commissioner