Energy Choice Matters

March 12, 2010

PUCT to Strike Provision Ceasing Billing of Wires Charges upon DNP of Switch-Hold Account

PUCT Commissioner Donna Nelson has proposed striking from a proposal for adoption related to meter tampering the provision that, once a REP submits a disconnect for non-pay for an account subject to a switch-hold, the TDU shall cease billing wires charges to the account (37291, Only in Matters, 3/8/10). The PUCT did not vote on the meter tampering proposal for adoption yesterday and will likely take a final vote at the April 1 open meeting.

As only reported in *Matters*, the DNP-related provision was added by Staff in a proposal for adoption released last week.

Nelson said that the TDUs have reported that they cannot easily segregate disconnected accounts based on a switch hold, and that to implement the provision, more time would be needed. Nelson, with the consensus of the other Commissioners, suggested striking the provision preventing the charging of delivery fees after a DNP.

Without that provision, a REP would only cease being charged delivery charges for an account subject to a switch hold upon submitting a Move-Out.

Commissioners also discussed how to divide funds received by the TDU, in excess of unpaid wires charges, related to tampering in excess of six months, when the TDU will be collecting such charges. Customers will be charged for both undercollected wires charges and energy charges related to the tampering, under the proposed rule. Even though neither the REP nor TDU will be assessed energy charges for the period beyond six months of tampering, Commissioners still feel that energy charges should be collected from customers in order to discourage customers from tampering by removing any associated benefit. However, as neither the REP nor TDU must be

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Calif. PUC Approves Phase-In of New Direct Access Load with Year One Limit of 35%

The California PUC approved a process to expand the amount of non-residential direct access up to the cap established under SB 695, which equates to about 11% of total retail sales (R. 07-05-025, Matters, 3/11/10).

Currently, about 5% of total retail sales across the state are direct access transactions.

The PUC adopted the revised four-year phase-in period which was exclusively reported by *Matters* yesterday. Under the new transition process, only 35% of available load under the direct access cap will be made available in 2010, instead of 50% as originally proposed. Up to 70% of the total open space under the cap will made available in Year 2 (e.g. an incremental 35%), up to 90% in Year Three, and 100% in Year Four.

The PUC otherwise adopted the mechanics of an earlier draft which were more fully explained in our 2/10/10 story.

Briefly, during 2010, an Open Enrollment Window will be used, during which time customers will receive a one-time waiver of the otherwise applicable minimum stay and notice requirements to leave utility supply. The waivers and Open Enrollment Window will only apply in Year One.

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Briefly:

DPL Energy Resources Receives Pa. Electric License

The Pennsylvania PUC granted DPL Energy Resources an electric supplier license to serve all customer classes in all service areas.

Interstate Gas Supply Expands Pa. License to Include National Fuel

The Pennsylvania PUC granted Interstate Gas Supply authority to market at National Fuel Gas Distribution Corporation in addition to Columbia Gas.

Reliable Power Alternatives Receives Pa. Broker License

The Pennsylvania PUC granted Reliable Power Alternatives Corporation an electric supply license as a broker/marketer serving all sizes of commercial, industrial, and governmental customers in all service areas.

Keytex Energy Solutions Receives Pa. Broker License

The Pennsylvania PUC granted Keytex Energy Solutions, LLC an electric supply license as broker/marketer serving commercial customers above 25 kW and industrial customers in all service areas.

Summit Energy Services Receives Pa. Broker License

The Pennsylvania PUC granted Summit Energy Services, Inc. an electric supply license as a broker/marketer serving all sizes of commercial and industrial customers in all service areas.

Clean Currents Receives Pa. Broker License

The Pennsylvania PUC granted Clean Currents, LLC an electric supply license as a broker/marketer serving all customer classes, including residential, in all service areas.

Calif. PUC Approves Tradable RECs

The California PUC adopted a decision to allow the use of tradable RECs for RPS compliance. Electric service providers and community choice aggregators will not be restricted to any limit on the use of tradable RECs for RPS compliance. The large investor-owned utilities will only be permitted to use tradable RECs to meet 25% of their annual RPS targets, during a phase-in period terminating December 31, 2011, absent Commission action. The utilities, and not competitive providers, are subject to a $50/MWh price cap on the use of RECs as well.

PUCT Publishes Prompt Payment Act Draft for Comment

The PUCT published for comment a proposed rule relating to REPs' obligations under the Texas Prompt Payment Act (37981, see discussion in Matters, 3/5/10).

Smitherman Suggests Keeping Deferred Payment Protection for Good Paying Customers

PUCT Commissioners were hesitant to remove current protections for customers with good payment histories, in discussing a Staff proposal for publication on deferred payment plans and related issues (36131, Only in Matters, 3/3/10). Commissioners did not vote to publish the proposed rule for comment yesterday, and will likely vote to publish the rule for comment at the April 1 open meeting.

Currently, any customer expressing an inability to pay, who has not received two disconnect notices in the past 12 months, must be offered a deferred payment plan by a REP. As only reported by *Matters*, Staff's proposal for publication would remove this provision, replacing it with (outside of weather emergencies) a provision that only certain vulnerable customers (such as those eligible for Lite Up) and customers who have experienced an "unexpected catastrophic event" are eligible for deferred payment plans.

Chairman Barry Smitherman said that customers with a record of paying their bill on time should still be able to go to their REP expressing an inability to pay and receive a deferred payment plan, given their sound payment history. Commissioner Kenneth Anderson also expressed concern about removing current protections afforded to customers in the rule.

Both Smitherman and Commissioner Donna Nelson support the ability of REPs to place a switch hold on customers agreeing to a deferred payment plan. Nelson noted, however, that placing a switch hold on customers on a levelized payment plan (an option REPs may offer customers in lieu of a deferred payment plan under the proposal) is more problematic, because, unlike the deferred payment plan, the levelized payment plan has no specific end date and may not be fully paid off, absent a final true-up. Anderson reiterated his concern about imposing a switch hold on customers on deferred payment plans.

In any event, Nelson reported that the logistics of implementing a switch hold for customers on deferred payment plans won't be ready until 2011.

Nelson also submitted redlined language for the proposed rule that would change the conditions under which a REP must offer a deferred payment plan outside of an extreme weather emergency. The Staff proposal used the number of heating/cooling degree days to trigger the REP's obligation to offer a deferred payment plan to a select group of customers, but Nelson has suggested changing the triggering event to whether ERCOT set a summer/winter peak in the prior month.

Nelson's redlined draft would also require that the customer pay 50% of the outstanding balance at the start of the deferred payment plan to initiate the deferred payment plan.

PUCT to Open Project on Wind, Ancillaries

The PUCT will open a rulemaking to address the issue of wind generation resources' responsibility for ancillary services, which has been debated for several months at the Wholesale Market Subcommittee and Technical Advisory Committee.

Chairman Barry Smitherman said that the issue is one of market design, and is better addressed at the Commission than at the ERCOT stakeholder level. Smitherman noted that the issue, if addressed by stakeholders, could devolve into one where one group of stakeholders looks to receive revenue from another group.

Issues to be addressed in the PUCT project include what kind of ancillary or reserve services will be required with the integration of more wind, what amount of such services will be required, and ultimately, what parties are responsible for such services.

Commissioner Donna Nelson also said that the Commission needs to be prepared to evaluate whether the market is sending the correct long-term signals to investors for new generation if the reserve margin is projected to drop below 12.5% any earlier than the current forecast, especially in light of various announcements of mothballings.

The PUCT does have a project currently open on generation adequacy (37339).

Commissioner Kenneth Anderson said that the assumptions which are used in the ERCOT reserve margin forecasts should be re-evaluated as some of the assumptions may be overly optimistic, such as the availability of mothballed plants.

Nelson also suggested that ERCOT charge more for interconnection studies so that only projects likely to get built file for such studies. The Commission could then, in turn, rely on the metric of current projects with interconnection studies with more certainty in evaluating potential new generation when reviewing resource adequacy.

PJM MMU: Must-Offer Requirement for Capacity Resources Should Apply Without Exception

PJM's Market Monitoring Unit (MMU) found most markets, including energy and capacity, to be competitive in 2009, but found that the regulation market results were not competitive, due to the revised definition of opportunity costs.

Among the recommendations from the MMU are that the obligation of capacity resources to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. "This means that capacity resources must be available every hour of the year at a competitive price," the MMU said.

Furthermore, the Reliability Pricing Model must-bid requirements must extend to all participants. "Thus, there should be no reduction of demand on the bid side. The current

2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability," the MMU said.

The must offer requirement for capacity should also apply generally to out of market transactions, the MMU said, such as construction of new capacity by: (1) regulated utilities receiving out of market payments for such capacity via rate base treatment of the investment; (2) companies receiving out of market payments for such capacity via long term contracts; (3) companies receiving out of market payments for such capacity via Reliability Must Run (RMR) payments; and (4) companies receiving out of market payments for such capacity under renewable portfolio programs.

"The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions and receive capacity credit if cleared and not receive capacity credit if not cleared," the MMU said.

"The must offer requirement should also extend to the elimination of the FRR (Fixed Resource Requirement) exception to capacity markets," the MMU added.

The MMU recommended that PJM take the required steps to ensure that capacity prices reflect local supply and demand conditions. "If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETO/CETL (Capacity Emergency Transfer Objective/Limit) analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM," the MMU said.

PJM, the MMU added, should perform a more detailed reliability analysis of all "at risk" units, including all units that do not clear in RPM auctions, units that do not cover avoidable costs, and units that face significant investment requirements due to, for example, environmental requirements.

The MMU recommended that PJM carefully consider the implications of the potential loss of the relatively small subcritical coal units identified as at risk in the MMU net revenue analysis and whether market design changes are required to address that potential loss. The MMU identified a set of coal units comprising 11,250 MW that, in 2009, did not recover avoidable costs even with capacity revenues and which, therefore, must be considered at risk of retirement.

In 2009, net revenues were not adequate to cover total fixed costs for a new entrant combustion turbine, combined cycle, or coal plant in any zone. While the results varied by zone, the net revenues for the combustion turbine and combined cycle technologies generally covered a larger proportion of total fixed costs, reflecting the greater significance of capacity market revenues for these technologies. For the new entrant coal plant, all zones show a significant decrease in net revenues compared to 2008, a result of lower energy prices and revenues.

The MMU found no exercise of market power in the capacity market in 2009, though it noted that the market suffers from "serious market structure issues" inherent in its design. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues, the MMU said.

"[T]he market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market," the MMU said.

"This is not surprising in that the Capacity Market is the result of a regulatory/ administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership," the MMU added.

The MMU recommended that any proposal to modify scarcity pricing include the following essential components: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; a maximum price of $1,000 per MWh; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; maintaining local market power mitigation mechanisms; and an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

The option to specify a minimum dispatch price under the Demand Side Emergency Program Full option should be eliminated, the MMU said, as all participating resources should receive the hourly real-time LMP less any generation component of their retail rate. "There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy," the MMU noted.

The MMU further recommended that the Demand Side Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. "There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP," the MMU said.

Regarding the non-competitive regulation market, the MMU said that the results are not due to the offer behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. "The regulation market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than its owner does," the MMU said.

The MMU found that energy prices fell 45.1 percent in 2009, that load fell 4.4 percent in 2009, and that congestion also declined by 66 percent. The MMU concluded that the decrease in prices was the result of a decrease in fuel costs and in load.

Tampering ... *from 1*

made whole with respect to energy charges beyond six months, there is a question of which entity is entitled to any funds collected by the TDU which are in excess of the amount needed to make the TDU whole for unpaid wires charges.

Commissioner Kenneth Anderson said that some of the funds should go to the REP, although the TDU should retain a significant portion as a fee for acting as a collection agent. Commissioners agreed that a 50/50 split of any funds received by the TDU in excess of funds needed to cover unpaid wires charges may be appropriate. REPs will not be charged for unbilled energy beyond six months, so do not need the funds to be made whole on that account, but do have a claim on such funds due to other long-term costs they may have undertaken to serve the customer (buying forward power, an allocation of overhead costs, etc.)

Some REPs have expressed concern about the TDU directly billing customers, as it would encroach upon the Texas market design of the

REP owning the relationship with the customer. The rule is silent on how TDUs would pursue collection, and some REPs envisioned that rather than billing customers as a traditional utility would, TDUs would pursue collection in court.

Calif. ... from 1

The Open Enrollment Window will begin on the effective date of the PUC decision and end 90 calendar days thereafter or on June 30, 2010, whichever comes first.

Direct access requests will be filled on a first come, first served basis, with all requests time-stamped. There are no carve-outs or preference for currently direct access-eligible load.

The utilities will begin accepting direct access Notices of Intent up to the Year 1 limit as of 9:00 a.m. PST on the fifth business day after the start of the phase-in period.

The draft sets the load caps, per SB 695, as shown below. Based on the recent level of direct access at each utility, the amount of available new direct access load is also shown.

Direct Access Load Cap in Annual GWh

	SCE	**PG&E**	**SDG&E**
Load Cap Pursuant to SB 695	11,710	9,520	3,562
Existing Base Line DA	7,764	5,574	3,100
New DA Load Allowance	3,946	3,946	462