Energy Choice Matters

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REPs Wary of Alternative Ratemaking for Distribution Utilities

Any significant changes to the PUCT's existing distribution ratemaking policy will involve some risk, the Alliance for Retail Markets said comments at the Commission (36358).

AEP has proposed alternative ratemaking methodologies to cure regulatory lag in collections, as well as reduce the increasing expenses of contested rate cases. As previously noted, such changes could increase the frequency of adjustments to the distribution rates paid by REPs (Matters, 11/14/08).

ARM argued that the allowance of "automatic pass-throughs" or any form of "piecemeal ratemaking" would have the effect of shifting risk to end-use consumers because regulatory lag -- an important factor in encouraging utilities to act efficiently -- would be diminished. Although there is no question that the current ratemaking process can be slow and cumbersome, it provides a great deal of scrutiny and transparency, ARM said.

Any change to existing ratemaking policy will significantly impact the relationship between a REP and the customers it serves, ARM said. The types of changes to ratemaking policy contemplated by alternative ratemaking would lead to more frequent adjustments to the distribution and other nonbypassable rates paid by REPs to utilities, "which will have significant retail pricing and market implications for REPs," ARM explained.

REPs are already charged a number of utility rate riders, including (but not limited to) Transmission Cost Recovery Factors, Transition Charges, Energy Efficiency Cost Recovery Factors, and Underground Facilities Cost Recovery Factors, all of which are adjusted at varying intervals and to varying degrees. The potential for additional utility riders with frequent adjustments could seriously

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Harris Worries Iberdrola Approval Opens Door for Utilities to Re-enter Generation Business

"The only effective way to completely eliminate the incentive and opportunity of a combined Iberdrola/Energy East to exercise vertical market power would be to require Iberdrola to divest its wind assets and forbid it from developing new ones," the New York PSC said in a full order authorizing Iberdrola's acquisition of Energy East, which permits Iberdrola to nevertheless own wind generation in New York (07-M-0906).

The order follows an abbreviated Commission order which approved the transaction in September, but did not completely outline the Commission's reasoning (Matters, 9/4/08).

Despite its conclusion that divestiture of Iberdrola wind assets is the only way to completely eliminate vertical market power concerns, the Commission noted that such a condition was not a realistic option in the case. Iberdrola made clear that a prohibition on wind generation ownership would be an absolute "deal breaker" from its point of view, and that it would decline to move forward with the acquisition under that condition.

However, the Commission said its Vertical Market Power Policy Statement allows a T&D utility to overcome the presumption regarding the unacceptability of vertical market power by demonstrating substantial ratepayer benefits, together with mitigation measures. The Commission concluded that the $275 million in Public Benefit Adjustments from the Iberdrola acquisition, which necessarily require that Iberdrola be allowed to continue to develop and own wind generation in upstate New York, constitute substantial benefits that justify Iberdrola's ownership of wind generation despite vertical

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ABATE Protests Gas Efficiency Charge on Transportation Customers

The Michigan PSC lacks authority to impose an energy optimization surcharge on transportation-only gas customers, the Association Of Businesses Advocating Tariff Equity (ABATE) argued in a request for rehearing of the Commission's temporary order authorizing collection of the volumetric fee from all customers (U-15800, Matters, 12/5/08).

The PSC's decision, "will likely result in unlawfully collecting millions of dollars from the wrong customers on one hand and simultaneously making retroactive collections from the correct customers legally difficult and practically complicated," ABATE said.

Act 295 of 2008, Subpart B, requires utilities to implement energy optimization programs, meant to reduce the consumption of natural gas and electricity by developing programs promoting energy efficiency and conservation by natural gas and electricity customers. Under its temporary order, developed outside of a contested case proceeding with no hearings or testimony, the Commission held that all customers of a natural gas utility, including transportation-only customers, will be subject to cost recovery charges for the energy optimization programs.

But ABATE countered that the statute explicitly states an eligible primary or secondary electric customer is exempt from charges the customer would otherwise incur under section 89 or 91 of the Act if the customer implements a self-directed energy optimization plan. Section 89 permits electric and gas providers to collect gas and electric energy optimization program costs from "natural gas customers" and/or "electric customers." Thus, ABATE argued that if a primary or secondary electric customer files a self-directed optimization plan, such customers can avoid all charges arising under the cited sections, including natural gas-related charges.

While the Commission considered such an interpretation to be a loophole, and doubted lawmakers meant to address the ability to avoid gas-related charges in a section aimed at primary and secondary electric customers, ABATE contended that its interpretation is the "unmistakable" literal construction of the Act the PSC must use.

ABATE noted the Commission's decision inserts language not present in the statute by finding that customers implementing self-directed optimization plans may avoid "some of" the charges under the cited sections.

Furthermore, Section 71(3) of the Act requires that energy optimization plans shall "ensure, to the extent feasible, that charges collected from a particular customer rate class are spent on energy optimization programs for that rate class."

Since transportation-only customers of natural gas providers purchase no gas from the natural gas utility, obviously the programs for which the utility surcharges are collected will not serve them, ABATE noted.

Detroit Edison Files Cost-Based Rates for Schools

Detroit Edison submitted to the Michigan PSC two proposed educational institution tariffs meant to implement cost-based rates for schools as required by Public Act No. 286 of 2008 (U-15751).

The redesigned educational tariffs result in a $21 million annual revenue decrease from the revenue collected under the currently applicable tariffs. Detroit Edison proposed a surcharge on all full service customers to recover the shortfall, to be collected upon approval of the new school rates. In the alternative, Detroit Edison suggested deferring recovery of the surcharge via a regulatory asset. The shortfall results from lower distribution rates.

Detroit Edison proposed a new secondary voltage tariff for schools (D3.2) and a new primary voltage tariff for schools (D6.2). The proposed tariffs are structured after the existing General Service Rate, D3, and existing Primary Supply Rate, D6.

Under D3.2, the energy charge for schools would be 6.966¢/kWh. Combined with the Power Supply Cost Recovery, Regulatory Asset Recovery Surcharges, and Enhanced Security fee, the total power supply cost for schools under D3.2 would be 7.03¢/kWh, versus the current 6.45¢.

Under D6.2, the on-peak energy charge would be 4.162¢/kWH, and the off-peak charge would be 3.8624¢. Rate D6.2 would include an $11/kW on-peak demand charge, plus voltage level discounts. Combined with the Power Supply Cost Recovery, Regulatory Asset Recovery Surcharges, and Enhanced Security fee, the total power supply cost for schools under D6.2 would be 6.65¢/kWh, versus the current 6.24¢.

EnerNOC Says Prohibition in Md. Gap RFP Would Destabilize Demand Response Market

The provision in the Maryland PSC Staff draft gap RFP which would prohibit demand response resources that cleared in the PJM 2011-12 Base Residual Auction from participating in the gap RFP won't prevent free riders as intended, but rather will destabilize the demand response market in Maryland, EnerNOC said in comments (9149)

Excluding demand resources that already cleared the 2011-12 auction is intended to eliminate free riders and prevent payments to resources that were already committed to the PJM capacity market (Matters, 1/6/09).

However, the measure is ineffective since the measure will not exclude existing customers that are already participating in PJM's demand response programs, EnerNOC noted. Under the PJM program, the obligation to supply demand resources in the 2011-12 delivery year belongs to the curtailment service provider (CSP). The obligation does not extend to the curtailment service provider's portfolio of existing end use customers participating in demand response, EnerNOC noted.

For this reason, the draft gap RFP will lead to arbitrage activity in which curtailment service providers who win the right to provide gap RFP resources will have the unfettered ability to compete for existing customers of other curtailment service providers, EnerNOC explained. The demand resources from existing customers will be able to count toward the gap RFP obligation, even if they are serving as demand response in the current delivery year and the customers' current curtailment service provider anticipated registering them as demand response through 2011-12.

"Unfortunately, this will lead to a disruptive 'poaching' of customers and chaotic customer churn," EnerNOC said. The exclusion provision places an artificial regulatory "straightjacket" on curtailment service providers that participated in the 2011-12 Base Residual Auction, and creates an unfair advantage to curtailment service providers who did not participate, EnerNOC cautioned.

Excluding 2011-12 demand resources from participating in the gap RFP would create a disincentive for future participation in the Base Residual Auction by curtailment service providers, yet such participation has helped decrease the capacity price paid by Maryland end-users, EnerNOC noted.

The measure is not needed, EnerNOC said, because the proposed Contract for Difference mechanism, along with a maximum bid price for the 2011-12 delivery year of $110.04/MW-day, will prevent free riders.

The $110.04/MW-day cap represents the Base Residual Auction clearing price for the 2011-12 delivery year. Thus, customers participating as a demand resource, whether they are new or existing customers, will not be able to be paid any additional money under the gap RFP, EnerNOC noted.

EnerNOC forecast that there is likely to be a relatively narrow pool of potential bidders in the gap RFP; almost certainly fewer than 10 bidders will participate, and perhaps as few as two to four bidders are likely to participate. "In addition, if substantial restrictions are placed on the eligible MW that can participate, and there is substantial uncertainty and apprehension about market distorting effects of the exclusion rule, CSPs are going to be reluctant to bid substantial volumes, or will do so only with substantial risk premium pricing," EnerNOC said.

Briefly:

Discount Power Prepares to Serve Conn. Customers

Connecticut start-up marketer Discount Power informed the DPUC that it has completed EDI testing with United Illuminating (Matters, 11/14/08, 9/19/08). An affidavit attesting to such EDI readiness is required at least 20 days prior to serving customers.

Ontario Energy Board Intends to Fine Two Marketers

The Ontario Energy Board provided separate notice to Universal Energy Corp. and Summitt Energy Management that the Board intends to levy administrative penalties against each marketer for various allegations regarding unfair practices. The Board would fine Universal $200,000 relating to reaffirmation calls made in the spring of 2007 and June of 2008, alleging that in 57 recorded calls with low volume electricity consumers, Universal representatives engaged in unfair practices, such as indicating the Board was canceling the regulated price plan in May 2008, or that customers would be subject to the true cost of power as the government removes a subsidy. The Board would fine Summitt $100,000, alleging Summitt failed to supply seven customers with a valid reaffirmation in the spring of 2008, and alleging Summit representatives made misleading statements in three transactions, such as that a government subsidy on rates was about to expire. The marketers may request a hearing on the allegations.

Pepco Urges No Action on Optional Climate Surcharge

Pepco agreed with the Maryland PSC Staff's recommendation to not pursue an optional, Pepco-only climate protection rider for customers. The rider, suggested in 2006 by a Montgomery County politician, would allow customers to elect to pay a surcharge that would be used to offset power plant carbon emissions. Pepco and Staff noted various measures have been developed to address carbon since the original petition, such as the Regional Greenhouse Gas Initiative, EmPower Maryland, the RPS, and the Maryland Climate Action Plan.

EnerNOC Signs Salt River Project

Salt River Project selected EnerNOC to provide up to 50 MW of demand response capacity under a three-year contract, beginning in the summer of 2009.

EnergyConnect Names New CEO

Demand response provider EnergyConnect Group named Kevin Evans CEO yesterday as current CEO Rod Boucher will take on a strategic development role as Chief Technology Officer. For the past five years, Evans has served as Chief Financial Officer and in other roles at the Electric Power Research Institute (EPRI).

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limit a REP's ability to offer fixed price products or to provide Electricity Facts Labels (EFLs) in accordance with the new disclosure requirements currently under consideration in Project No. 35768, ARM noted.

Reliant Energy argued that a scheduled timeframe must be set both for filing and the effective date of any changes under alternative ratemaking, in order to allow REPs sufficient notice to process the rate changes, including enough time to incorporate new rates into retail pricing. Such adjustments should be limited to not more that once per year (or once per two years), and should include 60 days' lead time before rates take effect so REPs have enough time to revise their billing systems to reflect the changes approved by the Commission, Reliant said.

The Office of Public Utility Counsel argued that PURA does not grant the Commission authority to approve alternative ratemaking methodologies that would permit an electric utility to adjust its rates outside of a full, traditional rate proceeding to account for a discrete set of costs. Unless specifically excepted, PURA § 36.201 prohibits the Commission from establishing a rate or tariff that authorizes an electric utility to automatically adjust and pass-through to utility customers a change in particular costs of the utility.

However, AEP explained that it was not seeking an automatic pass-through under its proposed forms of alternative ratemaking. Rather, AEP is seeking to accelerate and abbreviate existing schedules for Commission review of rate changes, by allowing individual factors to be adjusted outside of full rate cases. PURA contains neither an express prohibition against single-issue ratemaking nor a requirement that rates only be set in a full rate proceeding, AEP noted.

The Alliance of Xcel Municipalities, the Alliance of TXU/Oncor Consumers, the Cities Advocating Reasonable Deregulation, and the Texas Coast Utilities Coalition of Cities called regulatory lag an element of the risk associated with investment in a utility. Furthermore, regulatory lag and the cost of rate cases provide incentives to utility management to hold down expenses, the group said, which called itself the Coalition Of Regulatory Entities.

CenterPoint Energy contended an improved and more efficient approach to the regulatory process could be beneficial to all parties involved. For example, alternative ratemaking would benefit regulators by freeing up resources to focus on market oversight and other pressing concerns, CenterPoint said.

Iberdrola ... *from 1*

market power concerns.

The PSC noted that only a relatively small amount of total generation assets are at issue. The Order's requirement for Iberdrola to develop $200 million in wind generation corresponds to approximately 100 MW of completed wind construction. Similarly, Iberdrola's hopes for investment of up to $2 billion in the state translates roughly into a capacity of 1,000 MW, a level of capacity that is still relatively small compared to the total capacity statewide of over 40,000 MW, the Commission said.

"Our decision in this case does not change our policy on vertical market power. Any future PSL §70 filing that seeks our approval of the ownership of generation by a T&D company affiliate will need to demonstrate either that vertical market power cannot be exercised or that substantial ratepayer benefits, together with mitigation measures, overcome the presumption that would otherwise bar a T&D company from owning generation," the Commission said.

Still, Commissioner Maureen Harris, in a concurring opinion, felt the Commission's order left the door open for other utilities to seek approval to re-enter the generation market. Harris would have granted Iberdrola an "exception" to the vertical market power rule, given the unique circumstances in the case, rather than finding that Iberdrola has satisfied the test that ratepayer benefits permit the accrual of vertical market power under the Policy Statement.

"Creating an exception for Iberdrola from the Vertical Market Power Policy Statement would emphasize that its plans are not precedent for any other utility or T&D company affiliate to embark upon entry into the generation business. The Commission, by finding that Iberdrola has satisfied the Vertical Market Power Policy Statement, potentially opens the door to other utilities that might desire to pursue opportunities to develop generation," Harris said.

"This does not sufficiently protect the competitive electric markets that the Commission has been trying so hard to promote from the exercise of vertical market power. Granting an exception rather than finding the presumption was satisfied also would have emphasized that approving Iberdrola's acquisition is not an invitation to other utilities to re-enter the generation market, because an exception is based on unusual circumstances rather than a finding that benefits outweigh risks, a problematic finding under these circumstances," Harris noted.

Harris added that vertical market power could have been further mitigated by requiring Iberdrola to undergo a case-by-case review each time it proposed a new wind project. Permission to proceed with wind development would have been contingent upon a showing it had not exercised vertical market power. "The potential for the denial of that permission would have been a substantial deterrent against the exercise of vertical market power," Harris explained.

However, the Commission's adopted mitigation measures mostly consist of various reporting and monitoring requirements relating to interconnection, generator energy deliverability, congestion pockets, and Iberdrola generation holdings. The Commission also required Iberdrola to develop and own wind assets under a competitive affiliate, rather than through NYSEG or RG&E, and prohibited the utilities from signing power purchase contracts with an Iberdrola affiliate.