Energy Choice Matters
June 7, 2010

Stipulation Would Require Study of Moving Cap Rock to Retail Choice

A stipulation involving the acquisition of Cap Rock Energy by the parent of Sharyland Utilities would commit Sharyland to studying the potential introduction of retail competition into the Cap Rock service area, which is currently split between ERCOT and the Southwest Power Pool (37990, Only in Matters, 4/2/10).

Cap Rock's Stanton and Lone Wolf Divisions serve customers located in the SPP power region, and Cap Rock's McCulloch and Hunt-Collin Divisions serve customers located in ERCOT. The SPP portion of Cap Rock accounts for 75% of its load. Originally, Cap Rock was a cooperative when retail choice began, and was exempted from retail competition. As it transitioned to an investor-owned utility, legislation prohibited the introduction of retail choice to the service area, but that provision has since expired and the PUCT is free to direct a transition to competition as it sees fit, consistent with the requirements of PURA § 39.102(d)-(e). Cap Rock does not own any generation, and relies on purchased power to serve its load.

As part of the stipulation, Sharyland will analyze and evaluate a transition of the Cap Rock divisions, whether within or outside of ERCOT as of the execution of the stipulation, to retail competition in accordance with PURA § 39.102(d)-(e), and will develop a proposal (the "Retail Plan") regarding whether to move its customers which are ultimately located in ERCOT to retail competition. The Retail Plan is to be filed with the PUCT within 12 months of the closing of the acquisition, absent good cause shown.

Sharyland further agrees that the Retail Plan will:

(a) Provide sufficient provisions, and appropriate steps, to achieve retail competition within the

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PUCT Staff Proposes Distribution Cost Recovery Factor With Annual Adjustment

PUCT Staff have issued a draft proposal for publication for new Subst. R. §25.243 that would permit distribution utilities to create a Distribution Cost Recovery Factor (DCRF) that could be updated once annually on March 1 or September 1 (38298). The DCRF would function similarly to the mechanics of the interim Transmission Cost of Service rule.

Staff's proposal provides that a distribution utility could apply for inclusion of a DCRF in its retail electric service tariff, which is paid by REPs. Beginning with the calendar year after the Commission approves its DCRF, a utility could apply once every calendar year to update its DCRF. Any application for a DCRF or DCRF update would be required to be filed with the Commission on the 185th day before March 1 or September 1 of a particular year. The Commission would be required to suspend the effective date of the DCRF or DCRF update as necessary so that the DCRF or DCRF update would take effect on March 1 or September 1.

A separate DCRF would be calculated for each rate class consistent with the cost allocation approved in the utility's last base-rate case. The billing determinants for the DCRF would be weather-normalized for the 12 months ending on the same date used to determine the changes in

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Briefly:

Global Energy Solutions Seeks Pa. Broker License

Global Energy Solutions Corp. applied for a Pennsylvania electric supply license as a broker/marketer serving all customer classes in all service areas.

Paetec Receives Md. Broker License

The Maryland PSC granted Paetec Energy (Technology Resource Solutions, Inc.) an electric broker license to serve commercial customers in all service areas.

Patch Energy Services Receives Md. Broker License

The Maryland PSC granted Patch Energy Services, LLC an electric broker license to serve commercial and industrial customers in all service areas. Principal Don Patch was Director of National Accounts at Pepco Energy Services (Only in Matters, 4/21/10).

Patriot Energy, LLC Receives Md. Broker License

The Maryland PSC granted Patriot Energy, LLC an electric broker license to serve residential, commercial, and industrial customers at the four investor-owned utilities (Only in Matters, 3/15/10).

Maryland Energy Advisors Receives Md. Broker License, to Consult with Staff on Name

The Maryland PSC granted Maryland Energy Advisors, LLC an electric broker license to serve residential, commercial and industrial customers in all service areas, but directed Maryland Energy Advisors to share with Staff how it intends to market its service to avoid causing confusion or misleading customers due to the similarity of the broker's name and acronym with the Maryland Energy Administration (Only in Matters, 5/11/10).

Energy Professionals, LLC Receives Ohio Broker License

The Public Utilities Commission of Ohio granted Energy Professionals, LLC an electric broker/aggregator license to serve all customers in all service areas.

Amerex Brokers Seeks Maine Broker License

Amerex Brokers LLC applied for a Maine electric broker/aggregator license to serve medium and large non-residential customers in all service areas.

Md. Staff Says COMAR 20.59 Inapplicable to Easton Utilities Commission

Maryland PSC Staff have recommended that the Commission find that the competitive gas market rules contained in COMAR 20.59, by their terms, have no application to the Easton Utilities Commission since the rule only applies in areas where retail customers may choose their gas supplier, and Easton's distribution territory is not open to retail gas competition. As only reported in *Matters*, Easton had sought relief from the Commission with respect to COMAR 20.59, while still in development, to ensure that some of the customer-focused and metering rules were not applied to it notwithstanding the fact that Easton does not offer competition (Only in Matters, 3/19/09). Staff noted that the final rule explicitly limits COMAR 20.59 to retail choice territories. As COMAR 20.59 does not apply to Easton, the waiver requested by Easton is unnecessary, Staff said.

CMP Files to Increase Retainage Factor for Mass Market Standard Offer Customers

Central Maine Power has asked the Maine PUC to increase the current adder for uncollectible accounts associated with Standard Offer supply contracts for CMP's residential and small commercial class (the retainage factor) to 0.100 (e.g. 10%), from the current 0.015 level. The change would only affect contracts to be entered into commencing with the next Standard Offer solicitation, and would not affect current supply contracts. As of April 2010, CMP said that there is a deficit of $6.2 million in the retainage account for uncollectibles in the residential and small commercial Standard Offer class. This compares to a deficit of $864,000 just two years ago.

Portland General Electric to Pay $375,000 in OATT Violations Settlement

FERC has approved a stipulation under which Portland General Electric will pay a civil penalty of $375,000 for various violations of its OATT. Specifically, Section 28.2 of PGE's OATT states that the transmission provider, on behalf of its native load customers, shall be required to designate resources and loads in the same manner as any network customer under PGE's OATT. FERC's Enforcement Staff concluded that between January 1, 2002 and December 31, 2005, PGE violated sections 28.2 and 29.2 of its OATT by setting aside transmission capacity that was not adequately supported by designated network resources. Enforcement Staff concluded that PGE's violations impeded the Commission's goal of transparency in electric markets because of the unsupported set asides. Additionally, Enforcement Staff concluded that from January 1, 2002 through October 30, 2008, PGE provided an undue preference to its wholesale merchant affiliate (PGEM) by allowing PGEM to schedule firm point-to-point transmission service using non-public scheduling numbers 103 and 303 instead of using an OASIS reservation for the first leg of certain transactions. Enforcement Staff concluded that PGE's violations were not the result of manipulation, deceit, fraud, or material misrepresentation in an attempt to harm customers. "Rather, it appeared that the violations occurred as a result of a lack of attention to the Commission's requirements and PGE's OATT," a FERC report said.

WGL Says Winter 2009-10 Pilot Hedging in D.C. Cost $220,000

Washington Gas Light said that its 2009-2010 pilot winter hedging program for District of Columbia customers resulted in additional costs of $220,000, which had "virtually no impact" on customers' bills. The pilot winter hedging program is distinct from the summer storage injection hedging previously reported (Matters, 5/26/10).

NEM Recommends That D.C. Adopt Demand Response Load Profiles Ahead of AMI

The National Energy Marketers Association urged the District of Columbia PSC to implement a series of first-generation demand response load profiles that could be used to help prepare customers for the different pricing options proposed to be available from Pepco upon the installation of advanced meters in 2012 (FC 1056, Only in Matters, 4/15/10).

As only reported by *Matters*, Pepco has proposed transferring all SOS customers to a Critical Peak Rebate pricing option by 2014, with Critical Peak Pricing as an optional tariff.

"Given that Pepco's dynamic pricing implementation timeline does not begin until 2012, the interim time period represents an excellent opportunity to educate consumers about demand response through the availability of transitional DR load profiles," NEM said. As the name suggests, the demand response load profiles would still apply a generic pattern to settle a customer's usage; however, the demand response load profile would take into account some measure of "deemed" demand savings versus the standard load profile. NEM previously outlined the process before NARUC's winter meeting (Matters, 2/15/10).

NEM said that data captured by utilities and PJM can readily be adapted by the PSC and utilities to develop one or more first generation, transitional retail demand response load profiles to start to encourage load response behavior by residential and small-commercial customers as the full implementation of the smart-grid technology and related infrastructure occurs.

NEM further urged the PSC to, "ensure that all authorized market participants have secure, reliable, non-discriminatory (non-proprietary), open access to the information 'pipeline(s)' (IT infrastructures) that will be created to facilitate the 'smart grid.'"

"The data should be provided by Pepco to market participants on a real-time basis," NEM stressed.

Coincident with the availability of real-time access to data, NEM noted that marketers will also require access to Pepco's bill ready billing system.

ICC Issues Second Notice Order on ARES RPS Rules

The Illinois Commerce Commission has published a second notice order regarding RPS rules for alternative retail electric suppliers (Part

455), and has submitted the rules to the Joint Committee on Administrative Rules of the Illinois General Assembly (10-0109). The final second notice order differs little from the proposed second notice order in the case (see Matters, 5/11/10).

Among the modifications is the language agreed to by Staff and the Illinois Competitive Energy Association submitted during exceptions regarding the interaction of the use of alternative compliance payments and specific solar and wind goals. The adopted language states that, "For determining the number of megawatt-hours of renewable energy credits that must be purchased for compliance, an ARES may convert alternative compliance payment dollar amounts into megawatt-hour equivalents, by multiplying the payment by the total RPS percentage requirement and then dividing by the applicable alternative compliance payment rate (the latter expressed in dollars per megawatt-hour), at which point an ARES may allocate in any manner desired the megawatt-hour equivalents of its alternative compliance payments toward satisfying the wind, solar photo-voltaic, and non-specific renewable energy requirements for the compliance period."

The final order affirms a 36-month record retention requirement for customer contracts and bills, and affirms that such records may be kept electronically. The final order also affirms that suppliers may seek confidential protection for their RPS reports and supporting data.

Additionally, the ICC directed Staff to engage the parties fully and promptly in a collaborative process, if requested, to address the details or mechanics of Staff's illustrative compliance spreadsheet, and to maintain a current "informal/sample" compliance spreadsheet on the Commission's website that is to be posted well in advance of the September 1 annual compliance deadline. Staff recently created a webpage, with RPS information with the spreadsheet to be posted once rules become final (see Matters, 5/28/10).

CCAs Call PG&E Application to Flatten Rates Anti-Competitive

Moving the conservation incentive at Pacific Gas & Electric from generation rates to distribution rates represents, "classic monopoly strategy for fending off competition," the City and County of San Francisco said in commenting on a proposed California PUC decision (A. 06-03-005).

The proposed decision would accept a settlement which would eliminate PG&E's tiered residential generation rates (which have higher rates for higher usage) and replace them with a flat rate. A conservation incentive adjustment (CIA) would be added to distribution rates to create tiers designed to incent conservation and keep PG&E revenue neutral.

Community choice aggregators (CCAs) have called the proposal anti-competitive (Only in Matters, 4/9/10). San Francisco calculated that under the proposal, total generation revenues from San Francisco residential customers will decline by approximately 7%. "Unfortunately, these lower generation rates will not benefit customers at all; by virtue of the CIA, PG&E will make up for these rate decreases with a dollar-for-dollar increase in other rates," San Francisco said.

"Reducing rates for competitive services and increasing them for monopoly services is the classic monopoly strategy for fending off competition," San Francisco added, alleging that, "PG&E's apparent motivation for seeking the proposed rate changes is to make it more difficult for CCAs to compete against PG&E."

"It should come as no surprise that PG&E became interested in making these rate changes as Marin County and San Francisco were getting close to launching their CCA programs," San Francisco added.

The Marin Energy Authority said that adding the conservation incentive adjustment to regulated distribution rates, "removes an integral component of a CCA's energy service program: sending appropriate conservation incentives to its customers."

"The CIA effectively monopolizes conservation incentives by placing all meaningful economic incentives in the hands of the IOUs. CCAs, or any other LSEs for that matter, should be able to send their own conservation incentives to their own customers," the Marin Energy Authority said.

"The timing of PG&E's submittal seems quite surgical in consideration of the utility's many attempts to derail the MEA program and confuse customer comparison of utility and CCA service offerings," the Marin Energy Authority alleged.

The Marin Energy Authority also took the opportunity to make public a letter dated May 12 from the PUC's executive director to PG&E concerning PG&E's "immediate violation" of an earlier PUC letter directing PG&E to cease certain actions related to CCA opt-outs. Specifically, in a May 3 letter, the PUC directed PG&E to, among other things, cease sending out mailers that have the appearance of an official opt-out notice to its customers in Marin County for the purpose of encouraging these customers to opt out of the CCA program established by the Marin Energy Authority (Matters, 5/4/10).

The PUC's May 12 letter reported that PG&E responded on May 6 by stating that it was prepared to follow the course of actions outlined in the PUC's May 3 letter. However, the PUC subsequently learned that beginning on May 4, PG&E sent a letter to every customer that had not opted out of CCA service that was, "formatted in a manner that directly conflicts with the direction [the PUC] provided to PG&E just one day earlier."

"PG&E's immediate violation of my direction suggests that PG&E may be, in fact, acting in a deliberate manner to subvert the plain meaning of AB 117," the PUC's executive director said in the May 12 letter.

"PG&E's violation of my direction places PG&E in danger of the Commission's imposing significant and continuing fines and other penalties," the executive director added.

Aside from the instant application, San Francisco criticized the "scattershot changes to PG&E's generation rates and rate structure" that are either pending before the PUC or have recently been approved. San Francisco cited the PUC's recent decision to increase PG&E's Tier 3 residential generation rates and decrease its Tier 4 and 5 rates, collapsing the latter two tiers into a single tier in order to provide summer rate relief for high usage customers. The new rates went into effect June 1, but San Francisco noted that, "in a glaring omission, the [May] decision only states the changes to bundled rates; it does not identify the new generation rates or even specify a methodology for translating bundled rate changes into generation rate changes. As a result, CCAs [did not then] know whether or when PG&E's generation rates may change as a result of this decision."

Cap Rock ... *from 1*

Cap Rock divisions that currently reside in or will reside in ERCOT; and

(b) Outline the activities that must be accomplished prior to commencement of competition, and the order in which these activities should be accomplished.

Furthermore, Sharyland agrees to undertake a study of moving its Stanton and Lone Wolf Divisions from SPP to ERCOT. A third-party consultant would analyze and evaluate issues related to moving the Cap Rock Stanton and Lone Wolf Division loads into ERCOT, with the scope to be determined in a future PUCT project opened after the closing of the acquisition.

The ERCOT Study will address the following issues, in addition to any other issues that may reasonably be necessary for a complete analysis and evaluation of a move into ERCOT:

i. The costs to Cap Rock to move the Stanton and Lone Wolf Division loads into ERCOT, including the potential cost impacts to Cap Rock customers in all of its divisions;

ii. The potential impacts to a transition to retail competition in Cap Rock's divisions, including an analysis of these considerations in PURA § 39.102(d)-(e);

iii. The potential impacts to the SPP transmission system, including, without limitation, any avoided transmission investments; and

iv. The potential impacts to ERCOT, including, without limitation, an analysis of any necessary system upgrades and the benefit to ERCOT of having additional load in the West Zone.

The ERCOT Study shall contain a proposal (the "ERCOT Plan") regarding a possible move of the Cap Rock Stanton and Lone Wolf Division loads to ERCOT. Sharyland is to file the ERCOT

Study and Plan with the Commission as a docketed proceeding on or before six months after the closing of the transaction, except for good cause shown.

The cost to Sharyland of the ERCOT Study and Plan will be capped at $100,000.

In order to minimize any new stranded costs while the retail and ERCOT studies are being performed, Sharyland commits in the stipulation to undertake no new SPP-related obligations that would materially encumber or otherwise preclude a move of the loads in the Stanton and Lone Wolf Divisions to ERCOT, or the transition to retail competition. The no new SPP obligations commitment includes:

(a) Not joining the SPP in any capacity;

(b) Not joining the SPP open access tariff (OATT), which shall not preclude receiving service as a transmission customer;

(c) Not entering into any new purchased power agreements, futures contracts, forward contracts, or any other electricity derivative contract for power delivery in SPP that would preclude moving the Stanton and Lone Wolf Division loads to ERCOT;

(d) Not seeking to require an electric utility to provide electricity supply to Cap Rock that would preclude moving the Stanton and Lone Wolf Division loads to ERCOT;

(e) Not incurring costs that would be stranded by a transition of the Stanton or Lone Wolf Division loads to ERCOT or to retail competition;

(f) Not incurring any obligations for transmission expenses in SPP that extend beyond December 31, 2013; and

(g) Not entering into power contracts or power management agreements in SPP that extend beyond December 31, 2013, unless cancelable on 12 months notice or less with no termination fee or cost of cancellation.

Sharyland also agrees that during the pendency and implementation of the ERCOT Study and Plan, it will cooperate with Southwestern Public Service so that SPS will not be required to make significant capital investment or improvements in SPS's 230 kV lines serving the Midland and Borden County Interchanges, including Base Plan Upgrades recently authorized in the 2009 SPP Transmission Expansion Plan for the purpose of serving loads above 150 MW. Sharyland agrees to limit the total load on the SPP system to 150 MW, by use of interruptible loads, new resources, moving one or more distribution feeders or substations to ERCOT, or other reasonable means to limit load growth in the Stanton and Lone Wolf Divisions served from the SPP, so that such load shall not exceed the current capacity of the transmission facilities currently serving those divisions.

The stipulation was signed by Sharyland, Cap Rock, PUCT Staff, Texas Industrial Energy Consumers, Southwestern Public Service, and Pioneer Natural Resources USA, Inc.

DCRF ... *from 1*

invested capital used in the DCRF.

Costs recovered through a DCRF shall be reconciled in the utility's next full base-rate proceeding. The only issue the Commission would consider in the DCRF cost reconciliation is whether the changes in invested capital used in the DCRF were reasonable and necessary. Any over-recovered amounts based on costs found to be unreasonable or unnecessary would be refunded with carrying costs.

The DCRF would reflect (1) changes in invested capital, resulting from the addition and retirement of distribution facilities; (2) changes in federal income tax and other associated taxes resulting from the changes in invested capital; (3) changes in depreciation expense; and (4) changes in return on invested capital.

Staff said that the more timely recovery by utilities of changes in invested capital under the proposal will provide utilities with a greater incentive to invest in worthwhile distribution facilities because such utilities will not be required to apply for base-rate changes.