Energy Choice Matters

December 7, 2009

UGI - Gas Division Petitions Pa. PUC to Implement Purchase of Receivables

UGI Utilities - Gas Division petitioned the Pennsylvania PUC to institute a voluntary Purchase of Receivables plan for small volume customers, and to unbundle uncollectible expenses associated with Purchased Gas Costs from base rates through a Merchant Function Charge (P-2009-2145498). The proposal does not cover UGI's Central Penn and Penn Natural Gas divisions, which have already unbundled their uncollectible rates, but are not seeking to implement POR.

Under the proposed non-recourse program, UGI would purchase receivables at a discount for customers on Rate Schedule RT, and for customers with annual consumption not exceeding 300 Mcf on Rate Schedules CT and NT (e.g. the three small volume choice rate schedules).

UGI's proposed discount rate would include uncollectibles and an administrative factor as follows:

	RT	NT & CT
Uncollectibles	2.19%	0.36%
Administrative Factor	0.59%	0.59%
Total	2.78%	0.95%

The uncollectibles rate for each class would be equal the Merchant Function Charge applicable to bundled service customers on the similar non-transportation rate schedule (e.g. Rate R, CIAC, N).

Development costs would be recovered on a nonbypassable basis from all small volume, choice-eligible customers though a POR Implementation Cost Charge (Rates R, CIAC, N, RT, CT,

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Allegheny Files Revised Md. POR Discount Rates to Reflect Three-Year Amortization

Allegheny Power filed revisions to its proposed Maryland electric Purchase of Receivables discount rates to reflect the amortization of implementation costs over a three-year period.

The proposed new discount rates are:

Service Type	Revised Discount Rate	Originally Proposed Discount Rate
Residential SOS	0.98%	1.42%
Type I SOS	0.57%	1.01%
Type II SOS	0.58%	1.01%
Hourly-Priced SOS	0.36%	0.79%

The newly proposed rates reflect the following components:

Service Type	Development	Administrative	Uncollectible	Total
Residential	0.31%	0.05%	0.62%	0.98%
Type I	0.31%	0.05%	0.21%	0.57%
Type II	0.31%	0.05%	0.22%	0.58%
Hourly	0.31%	0.05%	0.00%	0.36%

The changes do not reflect any modification due to a list of Staff questions and concerns, which

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ABACCUS Market Ranking Still Shows Connecticut as Only Seventh-Best Residential Market

Connecticut, the hottest statewide residential market in the past 12 months, still ranks as only the seventh best residential retail electric market in the Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) published today by the Energy Retailer Research Consortium (ERRC). Rankings can be found below and on page 3.

Connecticut has seen residential migrated accounts grow from 131,000 as of October 2008 to 241,000 as of October 2009, or an 84% growth year over year. While there's no quarrel with Texas, New York and Alberta as the respective top three in the residential rankings, Connecticut, despite the prodigious growth, still ranks behind perennial re-regulation contender Maryland, Massachusetts (which has yet to even formally docket POR filings over a year after submission by the utilities), and Maine (which, unlike Connecticut, has actually ordered distribution utilities to sign a long-term supply contract, rather than just giving utilities the authority to enter negotiations).

Put another way, Connecticut residential load migration increased from 7% to 17% from October 2008 to October 2009. During the same period in Maryland, residential migration increased to 4.3% from 2.9%. Maine residential migration has been flat in the very low single digits. As a percent of residential accounts, shopping in Massachusetts only grew to 13.2% from 11.2% in the past year.

As in the 2008 ABACCUS study, the rankings of residential choice were determined with a 52% weighting based on elements of default service, likely leading to Connecticut's position relative to other jurisdictions with a two (versus three) year laddering process.

Residential ABACCUS Scores and Rank

Jurisdiction	2009 Score	2009 Rank	2009 Assessment	2008 Rank	2008 Assessment	2007 Rank	2007 Assessment
Texas	83	1	Excellent	1	Excellent	1	Excellent
New York	63	2	Excellent	2	Excellent	3	Good
Alberta	63	3	Good	3	Good	2	Good
Maryland	51	4	Marginal	4	Good	4	Medium
Massachusetts	51	5	Good	5	Medium	6	Medium
Maine	49	6	Marginal	6	Medium	5	Medium
Connecticut	47	7	Good	7	Good	10	Medium
Illinois	45	8	Good	10	Good	8	Medium
Pennsylvania	44	9	Good	9	Good	9	Medium
New Jersey	43	10	Marginal	8	Medium	7	Medium
District of Columbia	39	11	Marginal	11	Medium	12	Medium
Delaware	37	12	Marginal	12	Medium	13	Medium
New Hampshire	37	12	Marginal	14	Medium	18	Marginal
Ontario	36	14	Marginal	13	Medium	11	Medium
Rhode Island	33	15	Marginal	15	Medium	14	Medium
Ohio	32	16	Marginal	16	Marginal	17	Marginal
California	28	17	Unsatisfactory	17	Marginal	21	Unsatisfactory
Michigan	NA	18	Unsatisfactory	18	Unsatisfactory	15	Marginal
Montana	NA	19	Unsatisfactory	19	Unsatisfactory	19	Unsatisfactory
Virginia	NA	20	Unsatisfactory	20	Unsatisfactory	16	Unsatisfactory
Oregon	NA	21	Unsatisfactory	21	Unsatisfactory	22	Unsatisfactory
Nevada	NA	22	Unsatisfactory	22	Unsatisfactory	23	No Progress
Arizona	NA	23	Unsatisfactory	23	Unsatisfactory	20	Unsatisfactory

Commercial & Industrial ABACCUS Scores and Rank

Jurisdiction	2009 Score	2009 Rank	2009 Assessment	2008 Rank	2008 Assessment
Texas	84	1	Excellent	1	Excellent
New York	61	2	Good	2	Good
Maryland	61	3	Good	4	Good
Illinois	60	4	Good	3	Good
Maine	57	5	Good	6	Good
Massachusetts	55	6	Good	7	Good
District of Columbia	54	7	Good	12	Medium
Alberta	53	8	Good	5	Good
Connecticut	52	9	Good	8	Good
New Jersey	51	10	Good	9	Good
Pennsylvania	49	11	Good	10	Medium
Delaware	49	12	Good	11	Medium
New Hampshire	37	13	Marginal	15	Medium
Rhode Island	33	14	Marginal	14	Medium
California	33	15	Marginal	17	Marginal
Ohio	33	16	Marginal	13	Medium
Ontario	32	17	Marginal	16	Medium
Michigan	NA	18	Unsatisfactory	19	Unsatisfactory
Virginia	NA	19	Unsatisfactory	18	Unsatisfactory
Arizona	NA	20	Unsatisfactory	20	Unsatisfactory
Oregon	NA	21	Unsatisfactory	21	Unsatisfactory
Montana	NA	22	Unsatisfactory	22	Unsatisfactory
Nevada	NA	23	Unsatisfactory	23	Unsatisfactory

On the commercial and industrial side, Texas and New York maintained their respective 1-2 positions, with Maryland supplanting Illinois in the third spot, though with a very close score. Not only did Maryland jump one spot in this year's rankings, but its score increased significantly to 61 from 53 a year ago. While re-regulation is a bigger threat to small volume choice in Maryland, effective commercial choice is still threatened by the PSC's invitation for ratepayer-backed long-term contracting and utility-build generation proposals.

Also notable in the commercial and industrial rankings is the District of Columbia, which jumped five spots to #7 despite taking no substantive action on retail choice in the past year, aside from maintaining the two-year laddered procurement process for even the largest commercial customers. The District ranks ahead of several jurisdictions where the largest customers are either on hourly pricing or have fixed rates that vary quarterly, rather than annually, as in D.C. (ignoring seasonal rates).

ERRC made many of the same recommendations for successful retail market design as it did a year ago, including shorter-term procurement of default service supplies.

ABACCUS sponsors include Direct Energy, Green Mountain Energy, TXU Energy, and Shell Energy, with the Distributed Energy Financial Group serving as an administer. Project advisors included Pat Wood of Wood3 Resources, former PUCT and FERC chair, and Vicki Sandler, President of Wearthy Ideas and former President of APS Energy Services.

Pa. OCA Opposes Aspects of PECO Electric POR Changes

The Pennsylvania Office of the Consumer Advocate protested several aspects of PECO's proposal to revise its electric Purchase of Receivables program, including the proposal to recover ongoing operating and administrative costs through base rates.

As only reported by *Matters*, PECO applied to institute a temporary 0.2% electric POR discount rate for all classes, to recover $2 million in incremental IT costs. PECO expects such costs to be paid off by December 2011. Once the costs are paid off, the discount rate would be set at zero, with uncollectibles and administrative costs recovered in base rates (Only in Matters, 11/25/09).

OCA argued that the discount rate should not be temporary, and that ongoing operational and administrative costs should be paid only by customers on competitive supply through the discount rate, not all customers.

As it has consistently argued, OCA said that termination for non-payment of supplier charges under POR should be limited to the amount that would have been charged under default service, with the customer not subject to termination for non-payment of charges in excess of default service.

OCA also contended that suppliers should not be permitted to charge deposits for customers on POR, and should be required to accept all customers regardless of credit if using POR.

Redwood Resources Marketing Seeks $1.2 Million from PG&E in Complaint

Redwood Resources Marketing, LLC has filed a complaint against Pacific Gas & Electric at the California PUC resulting from a programming omission in PG&E's gas balancing system, which Redwood alleged caused Redwood to deliver natural gas to non-Redwood customers, and over-deliver the amount of natural gas needed for Redwood's actual customers (C. 09-10-016).

PG&E, while admitting a programming omission caused Redwood to deliver gas to customers for which it was not the supplier, said that since Redwood assigned its Core Transport Agent Agreement to Tiger Natural Gas in December 2008, Tiger is entitled to receive compensation, in the form of in-kind gas, for the errors. Redwood is arguing for a cash-out of the improper deliveries, plus fees and damages, in the amount of $1.2 million.

According to PG&E, the genesis of the error was Redwood's submission of enrollments for several incorrect customers in October 2005. While PG&E manually corrected the billing record of these erroneous enrollments, the changes were not recognized in the system interface between PG&E's customer billing system and the gas balancing system, which resulted in erroneous forecasts for Redwood.

PG&E reported that since the time the mismatch between the customer billing system and balancing system first occurred several years ago, it has sent Redwood monthly files for gas balancing purposes listing the erroneous customers, which PG&E said that Redwood should have identified. It was only in the fall of 2008 when Redwood discovered the errors, which PG&E said was in connection with audits Redwood was conducting in preparation of the sale of its customers to Tiger.

On December 1, 2008, Redwood transferred its customers, and assigned its Core Transport Agent Agreement, to Tiger. PG&E noted that under its Schedule G-BAL, which is incorporated into the Core Transport Agent Agreement, gas usage adjustments resulting from errors made by PG&E are made in-kind to the account of the affected Core Transport Agent.

A Consent Agreement to the assignment of customers between PG&E, Redwood and Tiger provided that any payments due under the Core Transport Agent Agreement were to be made to Tiger, the party that had been assigned the Core Transport Agent Agreement, and that Redwood released PG&E from all liability for making payments to Tiger, PG&E claimed.

As a result, and because after the sale Redwood was no longer active on PG&E's system and could not accept an in-kind payment, PG&E said that it made the in-kind transfer to correct the balancing system errors to Tiger, as the successor Core Transport Agent.

PG&E denied that it was required to cash-out the incorrect gas balance amounts as argued by Redwood, because PG&E said that the Core Transport Agent Agreement was assigned to another party, not terminated, and thus a cash-out is not permitted. PG&E denied that any errors caused Redwood to over-deliver the amount of gas needed for Redwood's actual customers.

MISO Files to Expand Ability of Demand Resources to Provide Spinning Reserves

The Midwest ISO filed at FERC to increase the extent to which Demand Response Resources - Type I (DRR - Type I) may be offered and used as Spinning Reserves, with tariff revisions that would allow DRRs - Type I to offer either Spinning or Supplemental Reserves, as well as Energy.

To be qualified to provide Spinning Reserves, DRRs - Type I must still have a Minimum Interruption Duration of sixty minutes or less.

Under the proposal, each Offer for a DRR - Type I will be required to identify its "Contingency Reserve Status," specifying whether the Resource will be cleared and deployed in the same manner done with regard to online Spinning or Supplemental Reserves, or in the same manner done with respect to offline Supplemental Reserves.

If a DRR - Type I selects "online" for its Contingency Reserve Status, and it clears Spinning Reserves, the Resource will be automatically deployed during any event in which Contingency Reserves are deployed, together with all other offered Resources that were cleared as online Contingency Reserves. In contrast, if the DRR - Type I selects "offline" for its Contingency Reserve Status, and it is cleared as Supplemental Reserve, the Resource shall be deployed during an event only if Reserves classified as offline are needed, and in that case, its deployment shall be based on economic order, comparing its total cost (shutdown, hourly curtailment, and hourly energy costs) with the start-up, no-load and energy costs of offline Generation Resources and Demand Response Resources - Type II.

If offered as online Spinning Reserve, the DRR - Type I will be compensated at the Market Clearing Price for Spinning Reserves for any reserves cleared. In such online deployment, the Resource commitments are not considered as Security-Constrained Unit Commitment (SCUC)-Instructed Hours of Operation, and as such, are not eligible for Revenue Sufficiency Guarantee (RSG) Make-Whole Payments of commitment costs under the Tariff. They would be, however, eligible for payment of the Real-Time Offer Revenue Sufficiency Guarantee Payment (RTORSGP). These eligibilities are comparable to the current treatment of an online deployment of a Generation Resource, which is not eligible for make-whole payment of commitment costs because of the deployment of Contingency Reserves, MISO said.

On the other hand, if offered as offline Spinning Reserve, the DRR - Type I will be compensated at the Market Clearing Price for Supplemental Reserves for any reserves cleared, and at LMP for delivered energy. Resource commitments will be deemed SCUC-Instructed Hours of Operation under the offline option, and as such, are eligible for RSG Make-Whole payments for commitment costs under the Tariff, as well as for payment of the RTORSGP. These eligibilities are comparable to the current treatment of an offline deployment for a Generation Resource, which is eligible for make-whole payment of commitment costs, as well as RTORSGP, for a commitment due to deployment of Contingency Reserves. In this regard, the Midwest ISO has exempted DRRs - Type I from the Offer flexibility requirement for eligibility for RTORSGP payments, because a DRR - Type I can only offer one reduction quantity, its Targeted Demand Reduction Level, so no flexibility is possible. But DRRs - Type I will be required to have the same Targeted Demand Reduction Level for each consecutive Real Time Must Run committed Hour; and they will be required to have Non-Excessive Energy levels above zero to be eligible for those payments, since its Non-Excessive Energy is the quantity for which the DRR - Type I is made whole by the RTORSGP.

Briefly:

MXenergy Confirms PPL Residential Entry

MXenergy confirmed Friday that it will begin offering a mix of fixed and variable contracts to residential customers at PPL. MXenergy declined to discuss pricing ahead of a formal announcement, which may come this week.

Eagle Industrial Power Services Receives Illinois License

The Illinois Commerce Commission granted Eagle Industrial Power Services an alternative retail electric supplier license to serve non-residential customers whose annual consumption is in excess of 15,000 kilowatt-hours in all service areas (Only in Matters, 10/29/09).

NiMo to Allow Gas ESCOs to Elect Customers' Sales Tax Rate

Niagara Mohawk filed at the New York PSC a revised gas Agreement for Billing Services and for the Purchase of Gas Accounts Receivable, with the amended document allowing gas ESCOs to choose the sales tax rate applicable to their commodity sales. Under the amended agreement, the ESCO shall provide the applicable sales tax rate for any new ESCO customer, and the customer will not be enrolled until the sales tax rate is provided by the ESCO. For an ESCO's current customers, the ESCO shall provide NiMo with the sales tax rate to be applied to each current customer via EDI or as otherwise directed by NiMo, and may subsequently provide NiMo with changes to the sales tax rates to be applied prospectively. Until the ESCO provides NiMo with sales tax rates for the ESCO's current customers, the rates applied to the ESCO portion of billed amounts shall be based upon the sales tax rates that would have been charged to the customer if the energy commodity had been provided by NiMo.

iZagg Energy Receives Texas Aggregation License

The PUCT granted iZagg Energy (Tampa, Inc.) an electric aggregator certificate (Only in Matters, 11/20/09).

EnerNOC Asks Md. PSC to Allow Customers at Small Utilities to participate in RTO Demand Response

EnerNOC petitioned the Maryland PSC to declare that customers at utilities with annual consumption of less than 4 million MWh may participate freely in PJM demand response programs. FERC Order 719 presumes that customers at these smaller utilities are not permitted to participate in such RTO programs absent express approval from the relevant retail regulator. In Maryland, utilities below that threshold, EnerNOC believes, are the Southern Maryland Electric Cooperative, Choptank Electric Cooperative, A&N Electric Cooperative, Berlin Electric Utility Dept., Easton Utilities Commission, Hagerstown Light Dept., Somerset Rural Electric Cooperative, and Thurmont Electric Dept. EnerNOC believes that under state law the PSC serves as the retail regulator for the Southern Maryland Electric Cooperative, Choptank Electric Cooperative, Berlin Electric Utility Dept., Easton Utilities Commission, Hagerstown Light Dept., and Thurmont Electric Dept, and asked the PSC to enter an order allowing customers at those utilities to unconditionally participate in RTO demand response programs. EneNOC believes that A&N Electric Cooperative and Somerset Rural Electric Cooperative do not meet the threshold of 1,000 meters which makes Maryland public service companies subject to PSC jurisdiction.

UGI ... from 1

and NT). As UGI only has 9,000 customers participating in its choice program, UGI said that recovering implementation costs through the discount rate would be unreasonable, and would raise each discount rate by an additional 1.05 percentage points. A nonbypassable charge of $0.0111/Mcf would recover the $800,000 in estimated development costs.

POR implementation would take 18-22 months. However, UGI said that it would institute the unbundling of the Merchant Function Charge almost immediately.

UGI would require suppliers to place all customers in a class on POR in order to participate. One class would consist of customers on Rate RT, and a second class would combine customers not exceeding 300 Mcf annually on Rates NT and CT. The all-in/all-out proviso would not apply to customers using more than 300 Mcf annually for Rates NT and CT, who are ineligible for POR.

The class-specific all-in/all-out requirement is needed to prevent suppliers from selling only high-risk receivables, UGI said. Should the Commission modify the all-in requirement, UGI said that it must be given the authority to develop supplier-specific discount rates to mitigate potential cherry-picking.

In connection with the all-in requirement, UGI would prohibit a supplier from participating in

POR for a class if any "affiliate" of the supplier serves that class of customers at UGI and does not utilize POR for that class. The term "affiliate" is not defined, and it's unclear whether the term could be interpreted as extending to independently controlled suppliers who may be deemed affiliates due to a common minority owner/investor (e.g. Sempra Energy Trading's interest in both Gateway Energy Services and now MXenergy).

Suppliers would be required to use utility consolidated billing to participate in POR as well. UGI consolidated billing is a rate ready only service.

Under UGI's proposal, all outstanding amounts billed on utility consolidated billing would not be purchased, and would be returned to the supplier for collection upon the commencement of POR. However, UGI would also require the supplier to transfer all previously collected customer deposits to UGI within 15 days of the start of the POR program)except for amounts related to termination fee risk).

Suppliers would not be allowed to charge customers included in POR a deposit except for a deposit designed to cover the risk of non-payment of a termination fee. UGI would be permitted to require POR customers to pay a deposit based on both delivery and supply charges.

Only basic supply service charges would be covered by POR, and not additional services provided by the supplier.

Under the proposed POR program, a supplier shall not, "pledge or attempt to encumber such amounts [purchased by UGI] as security." Receivables sold must be, "free and clear of all liens, claims an encumbrances."

The supplier must further warrant, "that it will not allow any interest or permit any third party to assert a claim of any type on those Purchased Customer Accounts or any new Purchased Customer Accounts during the term of this [billing services] Agreement."

UGI would be permitted to terminate a customer for non-payment of supply charges, regardless of the amount or relation to default service charges, under its proposal. Budget billing would be available to suppliers using POR.

Receivables would be paid to suppliers 40 days after billing.

Allegheny ... *from 1*

Allegheny said it will respond to in a separate filing (Only in Matters, 12/3/09). Allegheny said that it has no objection to Staff's proposed delay in implementing POR, so long as the Commission confirms such delay by December 9, which is the day Allegheny would otherwise finalize modifications to its billing systems to implement POR on December 15 as originally proposed.

Additionally, Allegheny, per suppliers' requests, filed estimated discount rates through 2013, though Allegheny stressed that the rates are estimates only and will likely change based upon uncollectible expenses and any over/under collections in the first year of the POR program:

Estimated Discount Rates

Service Type	2011	2012	2013
Residential	1.19%	1.14%	0.92%
Type I	0.78%	0.73%	0.51%
Type II	0.79	0.74%	0.52%
Hourly	0.57%	0.52%	0.30%