Energy Choice Matters

December 3, 2009

PUCT Raises Concern on Blocking Legitimate Move-Ins via Meter Tampering ESI-ID Flag

PUCT Commissioners are concerned about a meter tampering flag's affect on legitimate customer Move-In transactions, and are leaning towards a solution that would make it easier for customers to Move-In when their ESI-ID has been flagged for tampering, rather than a more time-consuming alternative which could delay energizing the account (37291).

As only reported in *Matters*, REPs and TDUs have outlined three possible scenarios regarding a flag process to identify ESI IDs associated with meter tampering, in order to prevent such ESI IDs from switching providers until settling with their current REP.

Under what is known as Option #1, TDUs would post a list of flagged ESI IDs which REPs would have to look up on a daily basis, and then compare such ESI IDs with any of their current customers or potential enrollments. Under Option #1, Move-In transactions would not be blocked by the TDU (though switches would be). REPs would be required to scrub new customer Move-In requests against the flag list to determine if any such Move-In requests are flagged. If so, REPs are to determine whether the Move-In is legitimate before sending the Move-In request to the TDU, which will be executed once submitted.

Alternatively, under Option #2, the TDU would notify a REP via MarketTrak when one of its ESI IDs is flagged for tampering. Additionally, under Option #2, the TDU would block any Move-In transaction for that ESI-ID until the REP submitting the Move-In request submits documentation

Continued P. 7

PUCO Approves SSO, SCO Auctions for Columbia Gas of Ohio

The Public Utilities Commission of Ohio approved a settlement that will implement Standard Service Offer (SSO) auctions at Columbia Gas for two consecutive delivery years starting April 1, 2010, with a Standard Choice Offer (SCO) auction scheduled to follow for service beginning on April 1, 2012 (Matters, 10/08/09).

The SSO and subsequent SCO auctions will replace the current bilateral procurement methodology and Gas Cost Recovery (GCR) mechanism. The first SSO auction for delivery beginning April 2010 will be held in February 2010.

However, the approved stipulation holds that because the contemplated SCO auction is some three years away, any party may, prior to the SCO auction date, petition PUCO to suspend the SCO auction in favor of another SSO auction. Hess Corporation stated that while it supports the stipulation as a whole, it does not support the proposed SCO auction. DTE Energy Trading, the Ohio Consumers' Counsel, and Ohio Partners for Affordable Energy stated that while they support the stipulation, that support should not be interpreted as support for SCO auctions in general, or in the stipulation.

The SSO auction procures wholesale gas allocated in tranches, pricing service at the NYMEX index plus an adder. In the SCO auction, specific customers (and associated requirements) are auctioned to retailers.

Continued P. 8

FirstEnergy Solutions Signs NOPEC to Long-Term Electric Contract

FirstEnergy Solutions has signed the Northeast Ohio Public Energy Council (NOPEC) aggregation program to a long-term electric contract for the period January 1, 2011, through December 31, 2019, further locking up a substantial amount of load for FirstEnergy Solutions.

Additionally, FirstEnergy Solutions said that it has signed a letter of intent with NOPEC's current supplier, Gexa Energy, under which FirstEnergy Solutions would replace Gexa as NOPEC's supplier in 2010. Terms were not disclosed.

The NOPEC contract is part of FirstEnergy Solutions' grant program to municipal aggregations, and will provide NOPEC with $12 million to disburse to member communities. The NOPEC aggregation includes about 500,000 customers.

Starting in January 2011, the contract provides that FirstEnergy Solutions' residential price shall be 6% lower than the applicable Price to Compare, with small commercial service priced at 4% lower than the Price to Compare, through the end of 2019.

In addition, residential customers who receive special generation credits from the electric utility for having electric space heating, water heating and/or load management equipment will receive a 4% discount off the Price to Compare from January 1, 2010, through May 31, 2012. The discount for these customers increases to 6% off the Price to Compare from June 1, 2012, to the end of 2019.

FirstEnergy Solutions said that generation savings under the contract are expected to total an estimated $19 million a year, based on current generation prices.

Under the governmental aggregation grant program, FirstEnergy Solutions has spent about $30 million to secure long-term contracts with aggregators representing 1 million customers of the 2.5 million customers at the FirstEnergy affiliated utilities.

PUCT Approves AEP Texas Smart Meter Deployment

The PUCT approved an unopposed stipulation that will permit AEP Texas Central and Texas North to deploy about 1 million advanced meters throughout their service territories from 2010 though 2013, with cost recovery through an advanced metering surcharge in effect from the January 2010 billing period through the December 2020 billing period (36928). The stipulation was first reported in *Matters*, and a full discussion can be found in our 11/13/09 story.

Under the stipulation, supported by all parties to the case except the Texas Industrial Energy Consumers who do not oppose the settlement, AEP Texas Central would charge Rider AMSCRF (Advanced Metering System Cost Recovery Factor) as follows:

TCC Monthly Fees For Billings Rendered

Rate	1/10-12/11	1/12-12/13	1/14-12/20
Residential	$3.15	$2.89	$2.26
Secondary ≤ 10 kW	$4.17	$4.17	$4.17
Secondary >10 kW Non-IDR	$2.05	$2.05	$2.05
Primary Non- IDR	$(7.07)	$(7.07)	$(7.07)

Texas North's Rider AMSCRF would be as follows:

TNC Monthly Fees For Billings Rendered

Rate	1/10-12/11	1/12-12/13	1/14-12/20
Residential	$3.15	$2.77	$2.35
Secondary ≤ 10 kW	$4.40	$4.40	$4.40
Secondary >10 kW Non-IDR	$1.46	$1.46	$1.46
Primary Non- IDR	$0.22	$0.22	$0.22

TCC and TNC will begin charging the rider for the advanced metering system (AMS) as of December 30, 2009 (the beginning of the January 2010 billing month).

After an initial pilot, full-scale commercial deployment of advanced meters will commence in the second quarter of 2010 for TCC in the City of Corpus Christi, and the second quarter of 2010 for TNC in the City of Abilene. A full discussion of the geographic schedule can be found in our 11/13/09 story.

AEP Texas will be able to support prepaid service (consistent with P.U.C. SUBST. R. 25.498) for customers with AMS-provisioned meters with remote connect/disconnect capability no later than April 30, 2010.

AEP Texas will also spend $1.2 million in capital costs and $3.8 million in operations and maintenance costs on customer education efforts, including information regarding how to shop for an electric provider.

As previously reported, the settlement applies trading margin refunds from a re-allocation of AEP East/West margins to reduce the otherwise required AMS surcharge.

Direct, RESA, WGES Outline Strategies to Improve Md. Mass Market

Residential and small business consumers require a "nudge" to test the competitive market in cases where the utility is the default option, Direct Energy said a briefing before the Maryland House Economic Matters Committee regarding electric choice. The Retail Energy Supply Association and Washington Gas Energy Services also appeared at the briefing.

Direct offered a three-point plan for creating a successful retail market. Among the recommended requirements is the development of a supplier referral program, which would allow suppliers to offer an introductory price to give mass market customers easy entry into the competitive market. Customers would be free to return to SOS anytime during the introductory period.

Direct further cited billing parity, achieved through purchase of receivables, as another element of its three-point plan. Noting that POR programs for all four investor-owned utilities are pending before the Commission, Direct urged lawmakers to monitor the progress of POR implementation.

Finally, Direct said that customer education is critical, as robust markets require informed and knowledgeable consumers. Direct and RESA cited the Connecticut and New York power shopping websites, as well as customer expos/forums held in New York, Pennsylvania and New Jersey, as tools to improve customer understanding of choice. RESA noted that the PSC has held supplier forums (most recently in June), and said that similar forums focusing on customers should be held.

RESA noted that there has been a 50% increase in residential shopping in Maryland over the last six months. However, the highest residential migration rate by service area is still only 8%, at Pepco.

WPTF: Calif. Resource Adequacy Draft Treats Retail Suppliers as "Second-Class Citizens"

A California PUC proposed decision which would add a multi-year forward commitment requirement to the current bilateral resource adequacy construct treats competitive suppliers as, "second-class citizens," and ignores the real potential that a forward, bilateral approach will drive retail suppliers out of the market due to its incompatibility with retail choice, the Western Power Trading Forum said comments on the draft decision. (R.05-12-013)

In a story first reported by *Matters*, the proposed order would reject a centralized capacity market, and instead require all load serving entities to demonstrate compliance with capacity obligations for five, four, and three years into the future. An LSE's initial (five year-ahead) showing would be at least 80% of its load assessment, rising to 100% by the three-year-ahead showing (Only in Matters, 11/4/09).

The combination of a multi-year forward requirement with a bilateral contracting approach, "will have significant harmful consequences to competitive wholesale and retail entities in the California market, and would thwart well-established Commission policies and commitments to competitive market formation," WPTF argued.

The draft, "clearly treats non-utility LSEs as second-class citizens whose legitimate concerns about survival of their business model are casually shrugged aside," WPTF charged, noting that while the proposed order states that the resource adequacy program should be neutral with respect to the treatment of different types of LSEs, the draft undercuts this finding by, "explicitly stating that the impact of the market design on retail choice is a secondary consideration," WPTF noted.

Competitive suppliers, WPTF added, will be at a competitive disadvantage in executing bilateral capacity contracts, as they cannot rely on ratepayers to guarantee the contracts, as utilities can. Higher costs from credit and collateral requirements from multi-year forward contracting, or from the risk of forecasting load that far out, "may well reduce the number of [competitive suppliers] participating in the retail market, thereby resulting in less competition and reduced market liquidity," WPTF cautioned.

Pacific Gas & Electric, however, whose proposal is the basis for the draft decision, argued that, "it is by no means clear that a multi-year forward requirement applicable to all providers is inconsistent with a competitive retail market." Furthermore, PG&E said that imposing a multi-year requirement solely on the IOUs, through the Long Term Procurement Plan (LTPP) process, and not on all providers, "is inconsistent with a competitive retail market."

"Direct access providers may prefer the simplicity and artificial cost advantage of a business model that does not include a multi-year resource adequacy obligation. But the preference of direct access providers to avoid any multi-year obligations does not mean that retail competition would be foreclosed by the imposition of that obligation on them as well as the utilities," PG&E argued.

Southern California Edison, though, called the forward bilateral approach unworkable in a market where customer migration occurs, favoring a centralized capacity market. As LSEs will not know their load five years out, the Commission will be required to implement a forecast-based process to allocate resource adequacy requirements, which SCE noted will undoubtedly be contentious.

"The potential high cost of managing multi-year forward capacity obligations and the risk associated with load migration will create incentives for LSEs to avoid carrying their equitable share of the [Resource Adequacy] requirement. Such a situation will place undue pressure on the administration of the program, and may unfairly impose costs on the default bundled portfolio," SCE reasoned.

Furthermore, SCE said that unlike a centralized procurement mechanism, the draft multi-year bilateral mechanism has no practical means to allocate a limited capacity requirement to numerous LSEs. "For example, if an additional generation facility is needed to meet a local area requirement, a specialized capacity requirement, or a new generation requirement, it is not feasible to require all LSEs, in a given IOU's service territory, to bilaterally contract for a portion of the required generation facility. In this instance, the limited capacity requirement will likely be procured under a backstop mechanism: either the CAM [Cost Allocation Mechanism] if acquired by an IOU under order by the Commission, or a FERC-approved and regulated CAISO backstop program," SCE noted.

In fact, under the proposed multi-year bilateral approach, SCE believes that most, if not all, of the required non-renewable new generation capacity will be procured under a California ISO backstop mechanism, subject to FERC jurisdiction, because individual LSEs will not enter into the necessary long-term contracts to develop new resources under their present business models. Such FERC oversight is why the draft order rejects a centralized capacity market, but the rejection serves no purpose as FERC will still have jurisdiction over the backstop procurements, SCE said.

Calpine, which favors a centralized market, said that should the bilateral approach be adopted, it can be improved by the following actions:

- Allowing head-to-head competition between new and existing generation in the IOUs' long-term solicitations;
- Permitting non-IOU LSEs to opt out of Cost Allocation Mechanism (CAM) allocations by demonstrating contracts for, or ownership of, resources that provide the same objective reliability benefits as the resources potentially subject to the CAM;
- Introducing load-slice auctions similar to those in place in many states in PJM, and
- Removing or raising the current resource adequacy program's $40/kW-year waiver price.

Conn. Draft Would Allow Co-ops to Displace Franchised Utility, Take Retail Service from EDC

A draft Connecticut DPUC decision would find that start-up electric cooperatives, under certain conditions, may take retail service from the applicable distribution utility, and resell such power to their members, with such sales neither subject to DPUC regulation, nor open to choice for the individual end users taking service from the cooperative. The ruling would essentially provide an opportunity for developers and property owners, by meeting certain conditions such as use of renewable energy, to engage in submetering, which removes the ability of submetered customers to access the competitive retail market (09-07-10).

The draft decision involves a petition for a declaratory order from Elm Electric Cooperative, which was recently formed to provide electric service to its members -- the tenants of a large, mixed use residential and commercial building now under construction and located at 360 State Street in New Haven, Connecticut. The DPUC had previously denied the property's developer, Becker Development, from submetering the property (Only in Matters, 1/12/09).

While Connecticut law generally prohibits creation of an electric cooperative in a franchised utility territory, in 1981 Conn. Gen. Stat. §33-219(b) was enacted, which holds that, "cooperative, nonprofit, membership corporations may be organized under this chapter for the purpose of generating electric energy by means of cogeneration technology, renewable energy resources or both and supplying it to any member or supplying it to, purchasing it from or exchanging it with a public service company, electric supplier, as defined in section 16-1, municipal aggregator, as defined in said section, municipal electric energy cooperative, in accordance with an agreement with the company, electric supplier, electric aggregator, municipal utility or cooperative."

Elm Electric Cooperative, which plans to install and serve customers using cogeneration from a 400 kW fuel cell, argued that it meets the statutory requirements to serve customers as a cooperative within United Illuminating's service territory, and that it is entitled to take retail service (including default retail supply service to supplement the fuel cell) from UI.

UI, as well as Connecticut Light & Power and the Office of Consumer Counsel, argued that while Elm Electric Cooperative could be formed, UI was only obligated to provide it with interconnection service, and has no obligation to serve it under a retail tariff, since the cooperative is essentially a wholesale entity because it is purchasing power for resale to its cooperative customers.

However, the draft finds that Elm Electric Cooperative is not a wholesale customer, and that it may take retail service from UI.

"As is unambiguously clear from the statutory language above, a section 219(b) cooperative is specifically authorized to generate and supply electric energy to any member, and may do so in a previously authorized franchise area, without the permission of the franchisee. The only catch is that the energy that it generates and supplies to its members must be by means of cogeneration technology, renewable energy or both," the draft concludes.

The proposed decision notes that statute gives such cooperatives "explicit legal authority" to "supply" electric energy to a member, and to "purchase" supply from an electric supplier, defined as an entity licensed by the Department that provides electric generation services to end use customers. The draft finds that a cooperative can supply electricity to its members and also purchase a portion of its supply requirements from the public utility, with such purchases resold to the cooperative customers.

Although Section 219(b) makes reference to "an agreement with the company" in delineating the cooperative's authority, the draft would hold that UI's tariff constitutes such an agreement governing retail service, and that Elm Electric Cooperative does not require UI's separate authorization to serve its customers.

The draft notes that the statute allows for the formation of an electric cooperative that generates or procures energy by means of cogeneration or renewable energy sources, but is silent as to the amount of cogeneration or renewable energy that must be generated or procured for the electric cooperative to exist.

Based on the "extraordinary privilege" that the law grants to cooperatives to supplant the franchised utility as the customer's retail provider, the draft would require a Section 219(b) cooperative to produce no less than 51% of its energy requirements from on-site cogeneration or renewable energy sources, and would require that 100% of the electric consumption of cooperative's members be produced or procured from cogeneration or renewable sources, setting a hurdle meant to prevent any property owner from simply installing a small fuel cell and declaring itself a cooperative not subject to DPUC jurisdiction but entitled to tariffed retail service.

Furthermore, given this finding, the draft would bar the cooperative from selling any RECs produced from its renewable energy system, since the power used to serve customers must retain the renewable attributes.

To the extent the on-site renewable energy system does not cover 100% of the cooperative customers' requirements, the cooperative must purchase RECs or renewable energy to meet the DPUC's mandate that 100% of the power used to serve cooperative customers is produced or procured from cogeneration or renewable sources.

National Grid Says Too Early to Determine Likely Cost Allocation of Any Cape Wind PPA

As tipped in yesterday's issue, the Massachusetts National Grid distribution companies and Cape Wind have agreed to enter negotiations for a long-term power purchase agreement from the proposed 170-MW offshore project, subject to DPU approval of the negotiations.

Any resulting contract would also be subject to DPU approval. Asked what form of cost recovery National Grid would pursue should a contract be executed (e.g. application to basic service only, or market sales with a nonbypassable credit/surcharge), National Grid replied that it is too early in the process to determine what form of cost recovery would be appropriate.

As required by the Green Communities Act, the DPU has established rules mandating that each distribution company shall conduct at least two separate solicitations for long-term contract proposals from renewable energy developers during the period from July 1, 2009 through June 30, 2014 (Matters, 6/15/09). The DPU refused to require distribution companies to make an up-front election on the form of cost recovery, as requested by retail suppliers.

Distribution companies are not required to enter into long-term contracts exceeding 3% of their annual load in the aggregate.

Briefly:

ICC Opens Formal Proceeding for New Retail Electric Rules

The Illinois Commerce Commission opened docket 09-0592 to address new electric consumer protection rules which have been the subject of stakeholder workshops led by the Office or Retail Market Development for over a year. Draft rules from ORMD were on the Commission's open meeting agenda yesterday, but were not publicly published as of yesterday evening. Per an earlier draft, the rules would cover marketing and sales, enrollment, rescission, termination fees, deposits, contract renewal, customer disclosures, sales agent training, and related topics. Specifically, the rules would be codified in new 83 Ill. Adm. Code 412 and an amendment to 83 Ill. Adm. Code 453.

PUCT Staff to Issue Strawman on Prepaid Service by December 11

PUCT Staff expects to file a strawman for new Subst. R. §25.499, relating to retail electric service using an advanced payment arrangement, by December 11, 2009, in project 35533. As previously reported, the Commission is examining what, if any, specific rules should govern prepaid service conducted without the use of an in-home prepayment device (with devices governed by §25.498), versus the Substantive Rules applicable to typical post-pay service (Matters, 10/23/09).

Md. Staff Requests More Info on POR Costs, Discounts from Allegheny

Maryland PSC Staff asked the Commission to suspend Allegheny Power's purchase of receivables compliance plan, and to direct Allegheny to provide further justification and workpapers supporting various calculations and aspects of the plan, in recommendations similar to Staff's recommendations regarding Delmarva Power (Only in Matters, 11/18/09). Among other things, Staff requested that Allegheny provide uncollectibles by distribution rate class, and explain why the risk factor component of the discount rate was set at 150% of the administrative cost discount factor (Only in Matters, 11/19/09). Additionally, Staff asked why the risk factor discount component should be identical for all customer classes, and asked that Allegheny provide support showing projections of the expected risk to, or loss of, the implementation cost recovery should the supplier-customer relationship not continue due to migrations to dual billing.

WGL to Hold Call with Suppliers on POR Versus Proration Today

Washington Gas Light plans to conduct a Maryland supplier conference call today to further discuss its decision to implement proration of receivables between supply and delivery costs, rather than developing a purchase of receivables program, to comply with COMAR 20.59, the National Energy Marketers Association said yesterday (Only in Matters, 10/9/09). NEM and other suppliers have urged WGL to reconsider its decision, and to pursue a POR program.

Broker Nania Energy Expands to Michigan

Broker Nania Energy said yesterday that it has expanded its procurement services to the Michigan electric market, notably at Detroit Edison where the 10% electric choice cap has not yet been reached. Nania, based outside Chicago, has brokered Illinois electric and gas load for a decade, and has hired additional Staff to focus on the Michigan market.

Exelon to Retire Four Uneconomic Units

Exelon Power said yesterday that it has notified PJM of its intention to permanently retire Units 1 and 2 at the Cromby Generating Station and Units 1 and 2 at the Eddystone Generating Station, effective May 31, 2011, citing the units' age and uneconomic position. All four units, located in suburban Philadelphia and built in the 1950s, are no longer economic to operate and are not required to meet shrinking demand for electricity in the region, Exelon said, citing decreased power demand, oversupply of natural gas, and increasing operating costs. Combined, the units total about 930 MW, and are powered by either coal or fuel oil.

PUCT Adopts New REP Certification Form

The PUCT adopted a new REP certification form as proposed by Staff in project 37053. A discussion regarding the new form can be found in our 11/26/09 story.

Meter Tampering ... *from 1*

showing that the Move-In is legitimately a new customer, and not the current customer trying to avoid the block on switching. Option #3 is similar to Option #2, and includes a block on Move-Ins, but would handle communication among REPs and TDUs differently.

Commissioner Kenneth Anderson expressed concern with Options #2 and #3, especially as they relate to tenants in apartment buildings. Anderson noted that as tenants frequently move in and out, it is likely that a legitimate new tenant might move into an apartment with an ESI ID of an account where the former tenant has tampered with the meter, resulting in a flag on the ESI ID. Under Options #2 or #3, the Move-In would automatically be rejected until the new tenant's new REP satisfactorily shows that the Move-In is legitimate. Anderson is concerned about how long this process will take to verify the legitimacy of a Move-In, as customers moving in will not want to wait several days, if not longer, to receive power.

Option #1, since it does not block any Move-Ins, would allay these concerns. Although theoretically the REP of a customer submitting a Move-In request would be encouraged to verify the legitimacy of the transaction under Option #1, presumably taking the same amount of time as Option #2 for the account to be energized, Anderson noted that, realistically, REPs will have a bias to enroll new customers, regardless of the flag. Thus, under Option #1, it's unlikely that execution of a Move-In will be delayed as the new REP may be less interested in investigating the flag and legitimacy of the transaction. This will also make it easier, however, for customers to game the switching restriction.

If the Commission does ultimately pursue Option #2 or #3, Anderson said that the rule must provide that REPs must contact the customer to verify the legitimacy of the Move-In within 24 hours, and that the rule must prescribe specific documentation that will be acceptable for the TDU to remove the flag on the ESI ID.

Chairman Barry Smitherman echoed Anderson's concerns, and said that, initially, the Commission should pursue a solution that makes it easier for legitimate Move-Ins to be honored, which would be Option #1. Smitherman also noted that there appears to be little disagreement among Commissioners that switch requests should automatically be blocked for flagged accounts, which Smitherman said should address most of the bad debt associated with the current ability of customers to switch REPs when owing amounts related to back-billing from tampering.

However, Michael Matlock, Director of Operations for Gexa, noted that about 20-43% of customers associated with tampering typically do not leave their current REP through a switch request, and instead leave their current REP via a Move-Out, which may be followed by an illegitimate Move-In. For Gexa specifically, 33% of tampered accounts leave Gexa via Move-Out and not a switch.

Staff reported that they are on target to present a proposal for publication on meter tampering for Commission vote at the December 17 open meeting.

Columbia SSO ... *from 1*

The settlement recognizes that, "Columbia has not expressed a present intent to, nor does this Agreement contemplate that Columbia seeks to, exit the merchant function."

The SSO auctions will be conducted in a manner consistent with Columbia's original proposal (see 2/17/09 story), similar to the descending clock auction used at Vectren and previously used at Dominion East Ohio.

The forecasted SSO/SCO requirements will be divided into 16 equal tranches, with each tranche, based upon current estimates, equaling approximately 5.0 Bcf. A maximum of four tranches will be awarded to any individual bidder, and this limit also applies to bidders that are affiliated with and/or have an interest equal to or greater than 10 percent in other bidders.

A fixed fee of 32¢/Mcf will be charged to choice and SSO/SCO suppliers for non-temperature balancing and peaking services, with the rate fixed for the life of the stipulation. Firm balancing service provided by Columbia will be priced the same for SSO and choice customers, ending the current disparity in pricing that favors sales customers.

Under the settlement, only the initial SSO suppliers will be required to purchase the natural gas left in storage. Columbia will sell between 2% and 4% of SSO suppliers' April 1, 2010 assigned Columbia Gas Transmission (TCO) Firm Storage Service (FSS) Storage Contract Quantity (SCQ) on April 1, 2010. Columbia will notify the bidders for the SSO auction of the amount to be left in storage that they must purchase per tranche, with such notice coming at least three weeks before the auction.

The settling parties agree, "that it is important that the capacity match as closely as possible on a monthly basis each supplier's customer group." Therefore, all assignable storage and transportation capacity shall be allocated and assigned on a monthly basis consistent with changes in the SSO/SCO/choice supplier customer groups. The stipulation provides that commodity held by each supplier in storage will not be included in any reallocation, and that each supplier will make its own arrangements with respect to such commodity supply. In addition, Columbia will meet with SSO/SCO and choice suppliers to discuss ongoing problems with the TCO electronic bulletin board.

There will be no change in customer eligibility requirements for transportation service through March 31, 2012 under the settlement. For the 12-months beginning April 1, 2012, customers eligible for the SCO or choice service will be:

(1) All customer accounts using less than 6,000 Mcf per year, and

(2) Human Needs customer accounts using 6,000 Mcf or more per year.

Transportation Service eligibility for 2012-2013 will be set as follows:

(1) Effective April 1, 2012, non-residential customer accounts using less than 6,000 Mcf/year must subscribe to 100% Standby

Service

(2) Non-residential Human Needs customer accounts with operable alternative fuel capability that consume 6,000 Mcf or more annually

(3) Other non-residential customer accounts that consume 6,000 Mcf or more annually

(4) Asphalt plants and grain dryers with annual usage less than 6,000 Mcf remain eligible for Transportation Service

(5) Public School Districts that are receiving Transportation Service as of the date of the stipulation, including any new or existing facility placed into service in any such Public School District during the term of the stipulation

After the initial SSO auction, Columbia will meet with stakeholders to discuss issues related to the installation of daily metering for Transportation Service customers; provided, however, that Public School Districts receiving Transportation Service as of the date of the stipulation will not be required to install daily metering during the initial term of the stipulation or thereafter until modified by the Commission.

Per the settlement, a Transportation Service customer may elect a Banking and Balancing Service bank tolerance equal to 1% to 4%, in 1% increments, of its annual throughput. If a Transportation Service customer elects and pays for a 1% to 4% bank tolerance level, that customer should be able to move a like amount in or out of the system each month, on an interruptible basis, subject to the parameters applicable to month ending volume banks if negative or in excess of the customer-elected bank tolerance level. Accordingly, the stipulation strikes Columbia's original proposal to impose a limitation on monthly bank changes.

Each year, Columbia shall restrict the positive balance for any Transportation Service shipper to an amount equal to 50% of the elected tolerance at the conclusion of each November billing month. Transportation Service customers shall be permitted to return to 100% of the elected tolerance thereafter.