Energy Choice Matters

January 22, 2010

FERC NOPR Would Mandate Weekly Settlements at All RTOs

FERC proposed a series of credit policy revisions for the organized markets yesterday that would, among other things, shorten the settlement cycle to "no more than" seven calendar days (RM10-13).

FERC claimed that the proposed changes in its Notice of Proposed Rulemaking, "will balance the need for market liquidity with appropriate risk management while ensuring just and reasonable rates for the nation's electric customers."

Among the policies proposed by FERC is mandating that all RTOs adopt a settlement cycle of "no more than seven calendar days with no more than an additional seven calendar days for final payment."

"Since the risk of default begins at the time the product or service is committed for delivery and continues until the account payable is ultimately extinguished, reductions in settlement periods would serve to: (1) lower the level of financial assurances required (i.e., collateral requirement provided by individual participants); (2) reduce the quantity of the aggregate level of payables outstanding at any point in time, thereby reducing the potential exposure of a defaulting entity; (3) enable updated transaction prices and charges to be utilized in a timely manner in determining credit risk exposure; and (4) provide earlier identification of default situations by lessening the opportunity for an unrecognized default and its severity," FERC said.

Weekly settlement has already been implemented in PJM. In other RTOs, such as the New York ISO, weekly invoicing has been deferred by opposition from load serving entities, which, due to

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PPL Completes Third Post-2010 Procurement

PPL Electric said that its third solicitation for default service supplies for the period Jan. 1, 2011, to Nov. 30, 2011 resulted in a winning price of $88.65/MWh for residential customers and $86.80/MWh for small and mid-sized businesses. The solicitation, which procured 17% of load following requirements, saw 18 bidders compete for load. PPL also purchased two 25 MW blocks of around-the-clock electricity supply at an average price of $50.85/MWh to serve residential customers from Jan. 1, 2011, to Nov. 30, 2011. The company also secured alternative energy credits needed for these blocks of supply. The price for these supply blocks is for energy only and does not include capacity and other charges, which PPL will purchase separately from the PJM market. All procurement results were approved by the PUC.

FERC Intermittent Resource NOI to Review Potential New Products for Capacity Markets

A FERC Notice of Inquiry regarding integration of "variable" energy resources (intermittent resources) seeks comments on whether the products included in capacity markets should be expanded, potentially layering costs for additional unbundled generation components onto ratepayer bills (RM10-11).

The NOI asks, as more intermittent resources choose to become capacity resources, whether existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services. "If not, what reforms may be necessary? For instance,

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Briefly:

Glacial Energy Expanding to Natural Gas Marketing

Glacial Energy, which has heretofore only marketed electricity, is expanding into several natural gas markets, Glacial said in seeking a Michigan alternative gas supplier license. Glacial also reported that it has a pending California retail electric license. In December 2009, Glacial named Joseph Cepparulo as Director of Gas Operations. Previously, Cepparulo was Manager of Gas Operations at MXenergy for three years. Entering the Ontario, Alberta, and Florida (gas) retail markets are also on Glacial's horizon.

PUCT Opens TCRF Rulemaking

The PUCT opened docket 37909 for a rulemaking to amend PUC Substantive Rule 25.193, relating to distribution service provider Transmission Cost Recovery Factors (TCRF).

PUCT Approves Certificate Amendment Recognizing Sale of TexRep7 to Green Line Power

The PUCT approved an amendment to the REP certificate of TexRep7, LLC, recognizing that TexRep7 has been purchased by Green Line Power. Green Line Power was founded by Clayton Fowler, founder and former president of REP Andeler Corp. (Only in Matters, 11/20/09).

Generators at Center of NYISO Extra-Tariff Mitigation Petition Identified

Unredacted filings (ER09-1682) from the affected generators reveal that the generators upon whom the New York ISO is seeking to impose extra-tariff mitigation are the combined cycle Saranac Facility owned Saranac Power Partners, L.P. (for whom Shell Energy North America acts as a bidding agent); the Batavia cogeneration facility owned by Seneca Power Partners, L.P. (Alliance Energy); and the Sterling cogeneration facility owned by Sterling Power Partners, L.P. (Alliance Energy).

Calif. PUC Affirms Cerritos Opt-In Aggregation, Load Cap

In a final order, the California PUC affirmed the City of Cerritos' right to operate an opt-in, direct access aggregation pool, but subjected Cerritos to a load cap equal to its share of the energy output of the Magnolia Power Project (see Matters, 1/21/10, 12/22/09). The Cerritos aggregation is unique, organized under AB 80, and differs from the community choice aggregations under AB 117 which must be conducted on an opt-out basis.

FERC Opens NOI on Whether Reliability Standard Creates Preference for Native Load

FERC has opened a Notice Of Inquiry (RM10-9) to determine whether Reliability Standard IRO-006-4 (Reliability Coordination - Transmission Loading Relief) directs a reliability coordinator to curtail a firm interchange transaction crossing over a constrained flowgate prior to curtailing a non-firm native network load transaction across the same flowgate. In a separate proceeding, several merchant generators had argued that under Reliability Standard IRO-006-4, firm transactions may be curtailed prior to non-firm transactions, resulting in an OATT violation. Merchant generators further argued that the Interchange Distribution Calculator used in the reliability standard is flawed because it does not take native load transactions into account when determining which transactions should be curtailed to relieve congestion.

FERC Finds SPP Longest-Term Rollover Matching Requirement Unjust and Unreasonable

FERC found that the Southwest Power Pool's requirement that, for an existing transmission service customer to retain rollover rights when all service requests cannot be accommodated, the existing customer must match the longest-term request for service in the queue is unjust and unreasonable, and inconsistent with Order 890's first-come, first-served requirements (EL09-40). FERC noted that in Order No. 890-B, the Commission confirmed that the first customer in the queue requesting service over a rollover eligible path is the potential competitor to the rollover customer, and that the rollover customer must only match that first customer's service term. "In contrast, SPP's section 2.2 contradicts the first-come, first-served principle by requiring the rollover customer to match the longest-term request, which may not be the first request in the queue," FERC said. By requiring the incumbent customer to agree to match the longest-term request rather than the first request in the queue, SPP's OATT creates a form of competition among potential customers that was not contemplated under Order 888 or Order 890, FERC added, in directing SPP to modify its OATT to remove the requirement for the rollover customer to match the longest term of service in the queue.

NRG Sells Padoma Unit to Enel

NRG Energy has closed an agreement to sell its terrestrial wind development company, Padoma Wind Power LLC, to Enel North America. Financial terms were not disclosed. Padoma is developing about 4,000 MW of potential projects in California. Enel North America will retain the entire Padoma development pipeline in California and Texas. NRG is maintaining its existing ownership interest in its three Texas wind farms: Sherbino, Elbow Creek and Langford, totaling almost 350 MW. The two companies also reached a co-investment agreement under which NRG will retain a Right of First Offer should Enel seek an equity partner in the Padoma Projects. Enel and NRG will also evaluate joint venture opportunities in wind as well as other renewable energy projects in North America.

Calif. PUC Adopts Gas Hedging Policies

The California PUC yesterday approved winter hedging policies for the natural gas LDCs (R08-06-025). At Pacific Gas & Electric, the PUC approved a settlement under which 20% of the risks from hedging will be borne by shareholders, with the remaining risks borne by core customers. At Southern California Gas and San Diego Gas & Electric, the amount of risk borne by shareholders, through the Core Procurement Incentive Mechanism, will be 25%, with 75% allocated to core ratepayers. Shell Energy North America had opposed the proposed settlement relating to PG&E, arguing that the provisions do not adequately increase hedging transparency, fail to limit rate volatility, and ultimately provide little incentive to hedge properly since shareholders would bear little risk. In the decision, the California PUC also declined to institute a fixed price tariff or other optional pricing mechanisms for core customers.

FERC Sets Trial-Type Hearing for PG&E, Pooling Authority Dispute

FERC set a dispute between the Power and Water Resources Pooling Authority and Pacific Gas & Electric regarding the California joint power authority's eligibility to take service under PG&E's Wholesale Distribution Tariff for a trial-type evidentiary hearing, stating that the case hinges on whether the Pooling Authority is able to show that its service request satisfies the requirements set forth in the second part of Federal Power Act section 212(h)(2)(B) (i.e., that it would utilize transmission or distribution facilities that it owns or controls to deliver energy to the requested new delivery points in the Glenn-Colusa Irrigation District). Such facts cannot be gleaned from a paper hearing FERC said (EL10-7, Matters, 10/22/09). FERC also affirmed that the case is within its jurisdiction since it involves a determination of whether the Pooling Authority meets the definition of "electric utility" under FPA section 3(22)(a).

FERC Sets Process for PJM Transmission Cost Socialization Remand

FERC established procedures and a schedule to commence a paper hearing to address the remand of high voltage, reliability transmission cost allocation in PJM, after an appeals court found that FERC's cost socialization approach was unjustified, as it requires customers not shown to benefit from the upgrades to pay a share of such costs (EL05-121-006, Matters, 8/10/09). To facilitate the paper hearing, FERC directed PJM to provide various data, including the total costs that have been approved through PJM's Regional Transmission Expansion Plan (RTEP) process for facilities that operate at or above 500 kV whose costs have been socialized. FERC asked parties to comment on purported benefits of the reliability upgrades experienced across pricing zones.

Calif. PUC Approves Procurement Process for SCE Solar Program

The California PUC approved a process for Southern California Edison to procure 250 MW of merchant solar power under its previously approved solar photovoltaic program. Among other things, the PUC, in Resolution E-4299, approved SCE's proposed annual solicitations for 50 MW of merchant solar power, rejecting recommendations from developers to front-load the procurement.

FERC Draft Would Expand Affiliate Waivers for Non-Controlling Holding Companies

FERC issued a Notice of Proposed Rulemaking which would grant blanket authorization for a holding company to acquire 10 percent or more, but less than 20 percent, of a public utility, provided that the holding company files a new form know as the Affirmation in Support of Exemption from Affiliation Requirements (RM09-16).

FERC said that the proposal is meant to ensure that certain acquisitions of public utilities by holding companies that do not influence the control of the utility do not trigger certain market-based rate requirements or cross-subsidization restrictions.

The Affirmation would ensure that a holding company purchaser will not change or influence the control of the public utility. The proposed rule would grant the affected public utility a waiver of certain regulatory requirements pertaining to an affiliate: specifically, the obligation to include the energy assets of the affiliate for purposes of a market power analysis, the change in status reporting requirement, and the affiliate transaction restrictions under Part 35 of the Commission's regulations.

The new process would allow FERC to monitor and sanction entities that violate any statements made in the Affirmation.

EPSA had originally filed a petition seeking the expanded blanket authorization in the fall of 2008.

FERC to Review Whether Munis, Co-ops Should Report Wholesale Sales

FERC has issued a Notice of Inquiry to determine whether it should require non-jurisdictional sellers to report wholesale sales on a quarterly basis (RM10-12).

Jurisdictional public utilities are required to file electric quarterly reports with the Commission detailing their wholesale sales. Publicly owned utilities, municipal utilities, public utility districts, rural cooperatives, and federal entities are currently exempt from the quarterly reporting requirement.

The U.S. Energy Information Administration estimated in 2007 that these publicly owned electric utilities account for 29 percent of electric utility sales. FERC noted that obtaining certain information in quarterly reports from such entities will help improve FERC's ability to effectively examine and monitor price formation, the number of sales, and the market concentration occurring in electric markets where these market participants play a large role.

"Because numerous market participants that are excluded from the Commission's section 205 jurisdiction do not file EQRs, a jurisdictional seller's market presence (i.e., its role in price formation) is difficult to determine," the NOI says.

The Energy Policy Act of 2005 gives FERC authority to ensure transparency in wholesale electric markets, and specifically grants FERC authority over otherwise non-jurisdictional entities for purposes of sales reporting.

The NOI also asks whether FERC should consider other refinements to the existing quarterly report filing requirements. The specific refinements include: (1) reporting the trade date (i.e., the date on which a transaction price is set) and the type of rate (i.e., fixed price, a formula, or an index); (2) reporting resales of financial transmission rights in secondary markets; (3) standardizing the unit for reporting energy and capacity transactions (i.e., dollars per MWh and dollars per MW/month); and (4) omitting the time zone from the contract section of the EQR.

FERC Expands Waiver from New Non-Interstate Pipeline Reporting Rules

FERC denied most rehearing requests regarding new requirements for major non-interstate pipelines to post daily scheduled volume information and other data for certain receipt and delivery points under Order No. 720, and affirmed that interstate natural gas pipelines must post information regarding the provision of no-notice service (RM08-2).

On rehearing, the Commission did grant an exemption from the posting requirements to all major non-interstate pipelines that deliver more than 95% of their annual flows to "end-users" as measured by average deliveries over the preceding three calendar years. In Order 720, FERC had only authorized the exemption if 95% of annual deliveries were to "retail customers," a narrower category than end users. On rehearing, FERC agreed with the American Gas Association, MidAmerican Energy, National Grid, and others that deliveries to end-users generally have the same effect as deliveries to retail customers (a subset of all end-users).

"The structure of natural gas price sales and transportation transactions by an LDC to end-users is irrelevant for purposes of interstate price formation," FERC said.

FERC also granted clarification with respect to virtual, pooling, or other points to which natural gas volumes are scheduled and yet where design capacity is unknown or does not exist, which were not addressed in Order 720.

"Based on the additional information received, the Commission finds that major non-interstate pipelines must post scheduled flow data for points where design capacity is unknown or does not exist with scheduled maximum natural gas volumes equal to or greater than 15,000 MMBtu on any day within the prior three calendar years," FERC ruled.

The Commission clarified that, as with posting related to points with a known design capacity, postings at points with no known design capacity are required only for scheduled volumes. The Commission is not requiring the posting of unscheduled natural gas volumes or actual flow.

Weekly Billing ... from 1

metering capabilities and statute or administrative rule, can typically only bill customers no more frequently than monthly. In a protest of PJM's weekly invoicing proposal, Hess Corporation had said that, "[t]he early payment would represent a direct, zero-sum, transfer of capital from LSEs to generators without any risk mitigation or other benefits to the market."

"The additional working capital burden is not trivial, especially within the context of today's tight credit market," Hess had said in its February 2009 comments on PJM's proposal, noting that the working capital costs may amount to hundreds of millions of dollars. FERC rejected Hess' concerns and permitted PJM to commence weekly invoicing.

In the NOPR, FERC, "recognize[s] that net wholesale buyers in organized wholesale electric markets may incur cash management costs by paying within the shortened timeframe, given that they receive revenues from their own retail buyers on a 30-day basis." To reconcile the discrepancy in cash flow, a market participant may need to arrange cash management facilities to manage the more frequent payments, FERC noted. The Commission invited comments on this proposal, and whether it would involve a one-time cost to establish such a facility or ongoing costs that could significantly affect liquidity and rates.

FERC further requested comment on the practicality of implementing daily settlement periods in the organized wholesale electric markets within one year of implementation of weekly settlement periods.

Other provisions of the NOPR include:

- Limiting unsecured credit to no more than $50 million per market participant in energy markets and eliminating unsecured credit in Financial Transmission Rights (FTR) markets
- Clarifying the ability of market administrators to offset amounts owed to market participants against amounts owed by market participants and to manage defaults
- Establishing minimum participation criteria for market participants
- Specifying circumstances in which a market administrator may invoke "material adverse change" to require a market participant to post additional collateral, and
- Limiting the time period allowed for posting additional collateral when additional collateral is requested, and whether two business days (as used in PJM) is appropriate

The NOPR itself provides no suggestions for the minimum participation criteria, instead seeking comments. FERC does state that the, "[m]inimum criteria should not be onerous, however, and should allow most traditional market participants - including small load-serving entities, municipalities, cooperatives, and other similar participants in organized wholesale electric markets - to participate."

FERC also sought comments on whether certain market participants with lower credit risks, such as municipals, should be subject to more lax credit standards.

Intermittent ... from 1

should the Commission examine formation of forward ancillary services capacity markets," the Commission asks.

Furthermore, FERC asks, "Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?"

The Commission noted that intermittent resources are typically only permitted to offer a portion of their nameplate capacity in capacity markets. "[T]o the extent existing rules limit the ability of [intermittent resources] to provide capacity services that they are capable of providing, the Commission seeks to explore whether such rules may be unduly discriminatory," FERC said.

Intermittent resources, FERC observed, do not typically participate in the day-ahead market due to the risk of making financial commitments. In light of the increasing number of intermittent resources, the Commission is interested in receiving comments on whether the lack of day-ahead market participation may be resulting in costly out-of-market commitments, thereby rendering rates unjust and unreasonable, as well as whether the financial risk associated with participating in the day-ahead market may unduly discriminate against intermittent resources by inhibiting their ability to participate in such a market.

"Should the financial risk of [intermittent resources'] participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics," FERC asked.

FERC will also explore whether the variability associated with increased intermittent deployment may result in an over-reliance on expensive reserves, such as regulation reserves. "The Commission seeks to ensure that reserves are being used efficiently such that the resulting rates are just, reasonable, and not unduly discriminatory. The Commission is also interested in ensuring that requirements for [intermittent resources] to contribute to system reliability are not unduly discriminatory," the NOI says.

The NOI will also examine the use of hourly scheduling for transmission service in unorganized markets (and imports to organized markets), and whether hourly scheduling is causing rates for reserves (as part of transmission service) to become unjust and unreasonable by inhibiting the ability of intermittent resources to establish operationally viable schedules, and preventing System Operators from utilizing the full flexibility of their systems. The Commission will explore whether greater scheduling flexibility, such as intra-hour scheduling, could provide benefits to the system and facilitate the reliable and efficient use of all resources.

The appropriate exemption for intermittent resources regarding scheduling imbalance penalties will also be examined. Other NOI topics include balancing authority area coordination and/or consolidation, and redispatch and curtailment practices necessary to accommodate intermittent resources in real time.

To assist in the development of superior forecasting tools for intermittent resources, FERC sought comments on whether the Commission should modify existing operational data reporting requirements. The Commission also aims to determine what data and what level of data-sharing is necessary, coupled with advanced communication and metering tools, to ensure that intermittent resources are integrated in a reliable and efficient manner, particularly with respect to scheduling, ramping needs, and the procurement of reserve services.

The Commission said that its goal, "is not to adopt rules that favor one type of supply source over another." Instead, the Commission's purpose in the NOI is to investigate market and operational reforms necessary to achieve two goals: first, to ensure that rates for jurisdictional service are just and reasonable, reflecting the implementation of practices that increase the efficiency of providing service; and second, to prevent intermittent resources from facing undue discrimination.