

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Credit Reforms in Organized Wholesale)
Electric Markets) Docket No. RM10-13-000
)
)

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association¹ (EPSA) submits these comments in response to the Federal Energy Regulatory Commission's (FERC or Commission) January 21, 2010 Notice of Proposed Rulemaking (NOPR) in the above captioned proceeding,² which proposes to standardize certain credit reforms across organized wholesale electric markets. EPSA has previously commented on a number of the NOPR's proposals in post-technical conference comments submitted after the Commission's January 13, 2009 conference on credit issues ("Credit Conference"). The proposals are both important and timely; EPSA appreciates the opportunity to comment.

EPSA's comments in the January 2009 administrative proceeding urged the Commission to act within its statutory authority to provide the greatest possible degree of regulatory certainty to energy markets. EPSA contended that certainty in the long term could be attained by assuring market participants that the Commission's regulations will not fluctuate indiscriminately, and in the short

¹ EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

² *Credit Reforms in Organized Wholesale Electric Markets*, 130 FERC ¶ 61, 055, Docket No. RM10-13-000 (January 21, 2010) ("Credit NOPR").

term could be attained by clarifying and standardizing credit policies to the extent that the Commission is able. EPSA is therefore supportive of several of the Commission's proposals, especially moving to weekly settlement periods, limiting the amount of unsecured credit available to each market participant and standardizing certain collateral requirements. There are some proposals that EPSA believes require more detail before it can support or oppose, namely the suggestion that the RTO become a counterparty in each electric transaction and that there be an aggregate unsecured credit cap for each corporate family in a given market.

I. COMMUNICATIONS

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II. COMMENTS

There is an important threshold question that should be addressed at the outset – should credit policies be standardized for each market and for each market participant?³ There is no doubt that some commenters in this proceeding will advocate sending all of these proposals to RTO stakeholder processes instead of requiring standardization across the markets. However, one of the

³ Credit NOPR at P. 1 notes that the Commission is “propos[ing] to require RTOs and ISOs to adopt tariff revisions reflecting the proposed credit reforms.” Further, at P. 11, the NOPR asks “for comment on whether the credit practices discussed below should be applied in the same way to all market participants or whether they should be applied differently to certain market participants depending on their characteristics.”

major issues identified by panelists at the Credit Conference was that differing credit policies across RTOs/ISOs create significant policy gaps that make it difficult for entities that operate in several markets to manage credit.⁴ Although EPSA has long supported each RTO's ability to maintain regional differences and urged FERC to give great deference to stakeholders within each region, EPSA supports reasonable standardization of credit policies in this case.

Stakeholders may deliberate on how exactly the Commission's proposed requirements will be crafted and inserted into the tariff. However, there must be some hard and fast goals that the Commission should enforce, namely achieving a weekly settlement period and concomitantly limiting the amount of unsecured credit available to each market participant as settlement periods shorten. Strengthening and standardizing credit practices within and across RTOs is an important tool for managing market risk, especially in the face of the recent financial crisis. The Commission should require standardization to the extent possible and credit policies should be applied uniformly to all market participants.

A. FINANCIAL SETTLEMENT TIMELINE

The NOPR proposes to require each RTO to "adopt a settlement period of no more than seven days and no more than an additional seven days to receive payment."⁵ EPSA strongly supports this requirement. The Commission is correct in stating that "credit risk exposure is, in large part, a function of the length of time between completion of the various parts of electricity transactions."⁶ At the Credit Conference, Morgan Davies of Calpine asserted that

⁴ All of EPSA's members operate in two or more markets.

⁵ Proposed Tariff Revision § 35.47 (b).

⁶ Credit NOPR at P. 13.

shortening settlement periods would be “the biggest driver in reducing credit risk,” explaining that shorter settlement periods “reduce [a market’s] cash conversion cycle... The shorter the cycle, the less risk of not performing,” Davies concluded.⁷ As it stands, the California ISO and the New York ISO are the only markets that have not yet moved to a weekly settlement timeframe; these two markets have monthly settlement timeframes.⁸ One reason given at the Credit Conference for not being able to provide weekly billing was the inability to get the necessary software. However, because most of the RTOs have found software solutions that will allow a one week settlement period, it is logical to assume that the remaining RTOs or ISOs can similarly obtain the software needed to achieve weekly billing. EPSA agrees with the Commission’s proposal to standardize a weekly settlement timeline across all RTOs and asks that the Commission enforce a strict implementation date for that change.

Further, the NOPR asks if the Commission should push toward an eventual move to daily settlement periods within one year of implementation of weekly settlement periods. This is something that perhaps the Commission should revisit in one year as shorter settlement periods prove beneficial to credit issues. EPSA has supported the shortening of settlement timeframes generally, but the proposal to move to daily settlement timeframes in all RTOs presents a number of questions. The RTOs must assess what the practical impact of becoming daily settling entities might be in terms of staffing and funding. Further, the impact of

⁷ *Transcript of Credit and Capital Issues Technical Conference*, discussion prompted by Commissioners Spitzer and Moeller, Docket No. AD09-2-000 (January 13, 2009), p. 107, lines 5-7.

⁸ The California ISO, however, recently moved to seven-day settlement periods with cash clearing periods of 29 days. See: <http://www.caiso.com/2457/24578ab961530.pdf> and FERC Docket Nos. ER09-1247 and ER09-1744 for more information.

unsecured credit limits that would likely further be reduced in a move to daily settlement should be evaluated. Thus, EPSA supports shortening settlement periods, but EPSA believes that the issues associated with such a ruling must first be fully vetted. After a seven-day settlement period has been achieved in all the organized markets.

B. UNSECURED CREDIT LIMIT

There are several proposals in the NOPR relating to unsecured credit. The NOPR proposes to directly require RTOs to include in their tariffs limitations of unsecured credit to \$50 million dollars per market participant and eliminate unsecured credit in FTR markets. Further, the NOPR questions whether there should be an aggregate cap for corporate families and if the unsecured credit cap should vary by market size.

i. NO MORE THAN \$50 MILLION PER MARKET PARTICIPANT

The NOPR proposes to “limit the amount of unsecured credit extended to any market participant to no more than \$50 million.”⁹ EPSA continues to support making unsecured credit limits commensurate with shorter settlement timeframes. EPSA agrees with the Commission that, “as the timeframe of the settlement shrinks, so does the amount of unsecured credit that a participant may need.”¹⁰ Limiting unsecured credit is an important step in protecting markets from financial and reliability exposure, and it is important that unsecured credit should be reduced in conjunction with accelerating settlement cycles. As EPSA advocates a weekly settlement period, a \$50 million unsecured credit cap per market participant is reasonable. This is an important step in standardizing

⁹ Proposed Tariff Revision § 35.47 (a).

¹⁰ Credit NOPR at P. 17.

credit procedures across markets and maintaining regulatory certainty. As such, this cap should apply to all market participants equally. The Commission did request comment on whether these proposals should “be applied in the same way to all market participants or whether they should be applied differently to certain market participants depending on characteristics.”¹¹ It is important for market certainty that this unsecured credit limit be evenly and universally applied.

ii. ELIMINATION OF UNSECURED CREDIT IN FTR MARKETS

The NOPR proposes also to “eliminate unsecured credit in the financial transmission rights market.”¹² EPSA supports the Commission’s proposal. FTR markets have products that are far less liquid than those in the energy markets and most of those products were developed before the credit policies of most RTOs. As the Commission correctly points out, FTRs have “a longer-dated obligation to perform which can run from a month to a year or more.” EPSA agrees that, because of the nature of the FTR product, different credit provisions are warranted in the FTR market than exist in other wholesale electric markets.

iii. FURTHER AGGREGATE CAP FOR CORPORATE FAMILIES

Though it is not proposed as new tariff language, the Commission asks if it should place a further cap (beyond that of the \$50 million per market participant) on corporate families.¹³ The NOPR gives very little information related to this proposal; it neither defines “corporate family” nor does it propose what the unsecured credit limit should be (though it does point to PJM as an example,

¹¹ Credit NOPR at P. 11.

¹² Proposed Tariff Revision § 35.47 (c).

¹³ Credit NOPR at P. 19.

which has recently set a \$150 million cap for affiliated groups).¹⁴ EPSA members report that defining “family of affiliates” in the PJM proceeding was particularly cumbersome in the stakeholder process, as was how the credit within the limit may be doled out among affiliates. These are questions that the Commission’s proposal does not pose or address.

Further, this proposal may not be appropriate for all market structures. An aggregate unsecured credit cap for an entire corporate family does not make sense in cases where both regulated utility subsidiaries and unregulated market participants are present in a holding company structure. For example, California utilities have their own stand-alone capital structure approved by state regulators as well as separate credit ratings that are usually equal to or higher than those of the parent company. And California regulators require that the state's regulated utilities are ring-fenced from their affiliates. A common cap would blur the required division between regulated and unregulated affiliates within a holding company. Therefore, an aggregate unsecured credit cap for an entire corporate family would not work in the context of California.

An acceptable alternative could be to assign an aggregated credit cap for all the unregulated subsidiaries within a holding company, and then separately extend credit for the regulated utilities within the holding company based on their stand-alone credit and financial information. The logic to this alternative approach would be to preserve cases where a ring-fenced capital structure and credit mechanism for regulated affiliates is a desirable and efficient structure to segregate differing lines of business, due to differences in cost-of-capital, need

¹⁴ *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,084 (2009).

for capital or as may be mandated by state and local regulation. At any rate, the Commission should develop a more specific and clear proposal, allowing for further public comment before considering whether to standardize corporate family caps. Noting the example of California, the Commission needs to further assess whether and how RTOs are handling their credit risk controls and, therefore, whether standardized limits, formulas or principles are appropriate.

iv. CREDIT POLICIES SHOULD APPLY TO ALL MARKET PARTICIPANTS EQUALLY

Finally, the Commission asks “whether the credit practices [proposed in the NOPR] should be applied in the same way to all market participants.”¹⁵ The NOPR seems to make the case that some market participants may need to have exceptional credit policies based on their characteristics. In support, the Commission quotes the testimony of Mr. Robert Levin, who said, “that [municipalities] are pretty good credit risks.”¹⁶ EPSA does not agree, and urges the Commission to require all RTOs and ISOs to apply their credit provisions equally to all market participants.

Municipalities and other like entities make the argument that they operated in a default risk-free environment because they have a regulatory guarantee with regard to cost recovery associated with serving native load customers. However, upon examination of the quantitative numbers, the concept of “risk-free” is not the case. To prove this point, EPSA refers the Commission to the failures of Colorado-Ute Electric Association, Inc., Public Service of New Hampshire, New Hampshire Electric Cooperative Inc., and the Wall Street Journal's recent story

¹⁵ Credit NOPR, P. 11.

¹⁶ Ibid.

on the growing number of municipalities that are considering Chapter 9 bankruptcy.¹⁷

There are a number of holes in the “risk-free” argument concerning regulated cost recovery. EPSA members have reported that recovery is also normally accompanied by a regulatory lag and a regulatory review for prudence. These issues create liquidity problems for companies with regulated recovery mechanisms, which then lead to failures and defaults.

Quantitative default risk can be calculated for all market participants. Credit policies should not hinge on any qualitative assessment of risk based on a regulatory guarantee. ISOs/RTOs should apply credit policies based on quantitative analysis. Regulatory guarantees are not protection from market volatility or a replacement for a sophisticated risk management and hedging program. The Commission should require ISOs/RTOs to apply credit policies equally to all market participants based upon the quantitative risk metrics of the member company.

C. RTOS AS COUNTERPARTIES TO ELECTRIC MARKET TRANSACTIONS

The Commission proposes in paragraphs 24 and 25 of the NOPR to require each RTO and ISO to become a party to electric market transactions. The proposal, as defined, does not take into account all of the potential ramifications of defining RTOs as counterparties. The NOPR frames this provision as a “clarification of status,” when it would indeed mark a major policy shift with significant legal, tax and financial implications. EPSA does not yet have

¹⁷ See: <http://online.wsj.com/article/SB10001424052748704398804575071591602878062.html>.

an opinion on whether or not RTOs should be counterparties to electric market transactions, but asks that the Commission more clearly define the problem it is trying to solve with this “clarification of status,” and develop a robust record from interested parties as to whether this is the correct solution.

First, it is important to point out that the case on which the NOPR relies to set up the problem is factually inaccurate as explained in the NOPR. In that case, defining the RTO as a counterparty to the transactions may not have made a difference. In the Mirant bankruptcy proceeding cited in the NOPR, the Commission seems to indicate that if the RTO had been a counterparty to the transaction, that fact would have obligated Mirant to pay CAISO as a debtor. However, the situation was not as simple as the NOPR described, and the fix therefore is not as simple as the NOPR proposes. As with most electric market transactions, there were multiple parties involved -- making CAISO a counterparty would not have reduced the transaction to a bilateral one between Mirant and CAISO. In fact, in this case Mirant was owed debt from the California Power Exchange (the “PX”) and Mirant potentially owed debt to CAISO.¹⁸ If CAISO had been a counterparty, there would still have been no mutuality established. When a default occurs, there is almost always more than one party involved and at fault. The Commission’s proposal to make an RTO a counterparty does not elaborate on how the RTO should act in the case of a

¹⁸ The California Power Exchange (or “PX”) declared bankruptcy at this time and held all of the receivables owed to numerous counterparties. See: Memorandum to CAISO Stakeholders from Dan Shonkwiler and Stacie Ford regarding the Counterparty Issue. (February 17, 2010), p. 3. It states: “Moreover, the later litigation that is the subject of FERC’s NOPR concerned a truly extraordinary situation with energy crisis refunds. The debt to Mirant arose from the default of the California Power Exchange, which itself had filed for bankruptcy. Under the Cal ISO tariff, Mirant was obligated to pursue collection of these sums from the PX, rather than the ISO.” Available here: <http://www.caiso.com/2741/2741793512f10.pdf>.

default and does not establish mutuality among all parties of the defaulting transaction.

Further, electric market transaction defaults and bankruptcy are not mutually exclusive concepts. One of the largest defaults in PJM's history – a December 2007 default of \$51.7 million from a group of companies collectively known as “the Tower Companies” – did not accompany bankruptcy. In that case, it may not have made a difference whether PJM was a party to the transaction.¹⁹ The NOPR does not go into great detail about this proposal. It includes one erroneous paragraph citing the Mirant bankruptcy proceeding in California and proposes to revise Commission regulations to require RTOs to become parties to electric market transactions. The Commission seems to be in search of a legal mechanism that would ensure RTOs can collect on defaults in electric market transactions, but in framing this as a “clarification of status,” the Commission minimizes a directive that could have major effects on the credit ratings of all RTO members.

The NOPR wisely “seeks comment on whether this clarification of status would have ramifications beyond addressing the risk highlighted here.” The Credit Risk Management Steering Committee in PJM have been discussing this issue at length and report that there are serious legal implications for an RTO to become a counterparty to electric market transactions:

None of this is meant to imply that such a move is trivial. Advice from PJM counsel indicates that issues related to CFTC registration (or obtaining a ‘no action’ letter), tax treatment and

¹⁹ *PJM Interconnection, L.L.C. v. Accord Energy, LLC*, 127 FERC 61,007 (April 2, 2009).

financial statements may need to be addressed. Some participants have also flagged potential tax implications.²⁰

One specific potential implication is that this proposal may affect the credit and financial statements of RTO members that would now have to include the RTO as a counterparty to all transactions. Each RTO though NE doesn't have one has a credit rating, but it has neither a statutory obligation nor a stated mission to maintain a high credit rating. If an RTO was a counterparty to all electric market transactions and its credit rating dropped, this would adversely affect the credit of the parties on all sides of each transaction, and it may trigger additional Securities and Exchange Commission (SEC) reporting requirements.

This issue is not ripe for a Commission ruling, though the Commission might consider it separately. While PJM is moving ahead on this issue, other RTOs have not even considered it. As EPSA continues to advocate for standardization, this is no exception. It would be confusing and potentially harmful for companies who operate in several markets to have one RTO clear all transactions by taking title or even flash title, while other RTOs do not. EPSA recommends that the Commission open a separate policy proceeding to consider this issue, as this proposal does not simply represent a "clarification of status" for RTOs, but a significant change in status from "non-party" to "party."

D. COLLATERAL ISSUES

The NOPR proposes to standardize certain issues related to collateral. Namely, it proposes that: (1) when additional collateral is required, it must be posted within a two-day timeframe; and (2) that RTOs specify in their tariffs when

²⁰ PJM Credit and Clearing Analysis Project Findings and Recommendations, Section 3.1 (June 2008) <http://www.pjm.com/committees-and-groups/closed-groups/~media/committees-groups/committees/crmisc/postings/market-reform-credit-recommendations.ashx>.

they may invoke “material adverse change” as a justification for requiring additional collateral.²¹ EPSA supports the Commission’s direction here, particularly standardizing the two-day timeframe for posting additional collateral across RTOs. However, EPSA is concerned that it may not be possible for an RTO to envision an exhaustive list of when it may need to invoke material adverse change provisions. It would be helpful for RTOs to work with stakeholders to produce an illustrative list of instances where material adverse change would be triggered, but RTO tariffs must include a clause indicating that case-by-case circumstances may also arise.

²¹ Proposed Tariff Revision § 35.47 (e) and (g).

III. CONCLUSION

Wherefore, EPSA respectfully requests that the Commission adopt the recommendations herein, including moving to weekly settlement periods, limiting the amount of unsecured credit available to each market participant and standardizing certain collateral requirements. EPSA asks that the Commission consider the suggestion that the RTO become a counterparty in each electric transaction in a separate proceeding, as the issue represents a substantial change in RTO party status and therefore requires a full and robust record.

Respectfully Submitted,



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March 29, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the Comments via email upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. March 29, 2010.

A handwritten signature in cursive script, appearing to read "N. Bagot", written in black ink.

Nancy Bagot, VP of Regulatory Affairs