EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of June 23, 2014

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 5, 2014 was circulated. New matters/proceedings since the last report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints

	Page	Matter	Date	Activity
	1	206 Investigation: FCM Performance Incentives (Compliance Proceeding) (EL14-52)	Jun 9	Notice of proceeding published in *Federal Register*; refund effective date Jun 9, 2014
			Jun 6-11	National Grid, NESCOE, NU intervene
	3	Base ROE Complaint (2012) (EL13-33)	Jun 19	FERC sets for hearing and settlement judge procedures Dec 2012 Complaint challenging the TOs' 11.14 base ROE
	3	Base ROE Complaint (2011) (EL11-66)	Jun 19	FERC issues *Opinion 531* (i) affirming in part and reversing in part the Aug 23, 2013 Initial Decision; (ii) announcing a new approach for the determination of public utilities' base ROE; (iii) establishing a limited paper hearing to allow briefs addressing the application of the new ROE approach announced in this proceeding; and (iv) changing the FERC practice on post-hearing ROE adjustments

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
	5	Attachment F Implementation Rule Waiver Request (NHT) (ER14-1989)	Jun 9	FERC grants NHT limited waiver of the Attachment F Implement'n Rule to allow certain reliability planning study expenses to be included only in RNS Rate True-Up; effective Jun 1, 2014
	5	Attachment F Implementation Rule Waiver Request (National Grid) (ER14-1686)	Jun 6	FERC grants waiver, in part, of certain provisions of Attachment F until Jan 12, 2015; effective date Jun 8, 2014
	6	FCA8 Results Filing (ER14-1409)	Jun 10	UWUA Local 464 answers Brayton Point Apr 25 answer
	8	ISO Securities: Capital Expenditures Refinancings (ES13-34)	Jun 17	ISO files "Report of Securities Issued" in connection with Jul 31, 2013 order

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

	Page	Matter	Date	Activity
*	8	Section 12 LOLE Demand Curve Changes (ER14-2153)	Jun 9	ISO and NEPOOL jointly file changes to Section 12 to reflect the implementation a system-wide capacity demand curve; comment date Jun 30
			Jun 23	NRG Companies intervene
	9	FCA9 ORTPs for On-Shore Wind and DR with DG (ER14-1477)	Jun 9	ISO and NEPOOL submit compliance filing striking the FERC-rejected on-shore wind tax credit adjustment; comment date Jun 30

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	16	Schedule 21-NU: Allocation of GSRP Localized Costs (ER14-2064)	Jun 12	MA DPU files notice of intervention
			Jun 20	CT PURA, National Grid submit supporting comments; MA AG/AIM file joint protest concerning allocation of CT and MA Greater Springfield Reliability Project Localized Costs

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	18	Capital Projects Report - 2014 Q1 (ER14-1954)	Jun 9	FERC accepts report
*	18	Order accepting SIL Values for the Northeast Region (ER14-225 et al.)	Jun 6	FERC accepts Simultaneous Transmission Import Limit values for the Northeast Region, including the New England Market
	20	Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)	Jun 19	ISO files its 23rd quarterly report

IX. Membership Filings

No Activity to Report

X. Misc. - ERO Rules, Filings; Reliability Standards

*	21	Revised Reliability Standards: VAR-001-4 and VAR-002-3 (RD14-11)	Jun 9	NERC files revised VAR Standards for approval; comment date Jul 14, 2014
	21	Revised Reliability Standard: PER-005-2 (RD14-7)	Jun 19	NERC approves PER-005-2; retirement of PER-005-1
	24	NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)	Jun 19	FERC issues NOPR proposing to approve MOD-001-2 and seeking further comment; comment date [60 days from the date of publication in the *Federal Register*]
	25	*Order 797*: New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations)(RM14-1)	Jun 19	FERC approves Geomagnetic Disturbance Operations Reliability Standard (EOP-010-1); EOP-010-1 to become effective Jan 1, 2015

XI. Misc. - of Regional Interest

	28	FirstEnergy PJM DR Complaint (EL14-55)	Jun 11	FERC extends the comment and response date to the date that is 30 days after the submission by FirstEnergy of an amended complaint
			Jun 6-17	Parties move to intervene

XII. Misc. - Administrative & Rulemaking Proceedings

*	30	Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)	Jun 19	FERC initiates proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets; first workshop to be held by early Sep
	30	Reliability Technical Conference (AD14-9)	Jun 10	FERC holds technical conference; written comments may be submitted through Jul 15, 2014
			Jun 12	Speaker materials posted on eLibrary
	31	3rd-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services (AD14-7)	Jun 9-10	Parties submit post-workshop comments
			Jun 12	Transcript posted on eLibrary

*	31	NOPR: MBR Authorization Refinements (RM14-14)	Jun 19	FERC issues NOPR; comment date [60 days after publication in the *Federal Register*]

XIII. Natural Gas Proceedings

35	NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)	Jun 18	NAESB submits status report regarding activities in response to Gas-Electric Scheduling Coordination NOPR; subsequent report to be submitted on or before Sep 29, 2014
36	*Order 787-A*: Gas/Electric Operational Info Sharing (RM13-17)	Jun 19	FERC denies rehearing and/or clarification of *Order 787*
37	Natural Gas-Related Enforcement Actions: BP (IN13-15)	Jun 13	BP requests rehearing of May 15, 2014 order establishing hearing
		Jun 13-19	Subpoena *duces tecum* issued to Energy Transfer Partners, Enbridge, Kinder Morgan, Atmos, Enterprise Products
		Jun 17	BP's request for order limiting discovery denied

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

38	2013/14 Winter Reliability Program (14-1104 and 14-1105)	Jun 6	TransCanada and RESA file petitions for review of the FERC's orders on the 2013/14 Winter Reliability Program
38	2013/14 Winter Reliability Program Bid Results (14-1103)	Jun 6	TransCanada files a petition for review of the FERC's orders on the 2013/14 Winter Reliability Program Bid Results Filings
40	PPL EnergyPlus, LLC v. Nazarian (MD PSC Cfd Order) 4th Circuit (13-2424)	Jun 16	MD PSC and CPV Maryland petition 4th Circuit for rehearing *en banc*
		Jun 17	4th Circuit stays its mandate pending the requested *en banc* ruling

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: June 23, 2014

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the Federal Courts and legislatures through June 23, 2014. If you have questions, please contact us.[1]

I. Complaints

- **206 Investigation: FCM Performance Incentives (Compliance Proceeding) (EL14-52)**

As more fully explained in Section III below (ER14-1050), the FERC instituted this proceeding, pursuant to section 206 of the Federal Power Act ("FPA"), in its May 30 *PI Order*, having concluded in the *PI Order* that the ISO's existing Tariff, specifically the current FCM payment design, "is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits."[2] The FERC directed the ISO to submit in this proceeding "Tariff revisions reflecting a modified version of its proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's proposal."[3] The FERC-established refund effective date will be June 9, 2014.[4] Since the last Report, interventions were filed by National Grid, NESCOE, and NU.

- **206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23)**

As previously reported, on March 20, 2014, the FERC initiated this proceeding, pursuant to section 206 of the FPA, to ensure that ISO-NE's scheduling, particularly its Day-Ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices to be ultimately adopted by the FERC in RM14-2 (*see* Section XIII below).[5] Noting its concern about the lack of synchronization between the day-ahead scheduling practices of interstate natural gas pipelines and electricity markets, the FERC directed each ISO and RTO, including ISO-NE, within 90 days after publication of a Final Rule in Docket RM14-2 in the *Federal Register:*

> (1) to make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *ISO New England Inc. and New England Power Pool,* 147 FERC ¶ 61,172 at P 23 (May 30, 2014) ("*PI Order*").

[3] *Id.* at P 1.

[4] The June 3 notice of this proceeding was published in the *Fed. Reg.* on June 9, 2014 (Vol. 79, No. 110) pp. 32,937-89.

[5] *Cal. Indep. Sys. Op. Corp. et al.*, 146 FERC ¶ 61,202 (Mar. 20, 2014). The New England 206 proceeding was docketed as EL14-23.

Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or (2) to show cause why such changes are not necessary. In their responses, each ISO and RTO must explain how its proposed scheduling modifications are sufficient for gas-fired generators to secure natural gas pipeline capacity prior to the Timely and Evening Nomination Cycles.[6]

The Commission expects to issue a final order in this section 206 proceeding within 90 days of the filings required under the March 20 order. Interventions by over 40 parties, including one by NEPOOL, were filed in the New England-specific docket. On April 10, Puget Sound submitted comments addressing the changing of RTO/ISO practices, including a request that RTO/ISOs be required "to adopt consistent timelines that require bids awards to be submitted prior to the natural gas timely and evening scheduling deadlines". This matter is pending action in RM14-2. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Administrative Pricing Rules Complaint (EL14-7)**

Rehearing and clarification remains pending on both of the FERC's January 24 FCM Administrative Pricing-related orders that (i) granted in part, and denied in part, NEPGA's Administrative Pricing Rules Complaint in this proceeding,[7] and (ii) accepted changes to the FCM Administrative Pricing Rules in ER14-463 (*see* Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463) below).[8] As previously reported, in the *Jan 24 Orders*, the FERC found that the administrative pricing provisions for situations of Inadequate Supply and Insufficient Competition were unjust and unreasonable. While the FERC declined to adopt NEPGA's proposed revisions, it adopted the revisions proposed by the ISO in its Exigent Circumstances Filing in ER14-463 and also declined to find the existing Capacity Carry Forward Rule unjust and unreasonable.[9] In its request for rehearing and clarification of the *Jan 24 Orders*, NEPGA requested the FERC: (i) require prospective auctions to utilize ORTP-based prices; (ii) direct ISO-NE to implement for FCA9 a sloped demand curve for all aspects of the FCM, including for individual capacity zones; and (iii) require ISO-NE to eliminate the zero-bid requirement and implement the bidding protocols requested by NEPGA in its initial Complaint in this proceeding. On March 24, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NESCOE FCM Renewables Exemption Complaint (EL13-34)**

Rehearing of the FERC's February 12, 2013 order denying NESCOE's FCM Renewable Exemption Complaint[10] remains pending before the FERC. As previously reported, NESCOE instituted this December 28, 2012 complaint in response to the ISO's December 3, 2012 FCM compliance filing that implemented buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO's proposed Minimum Offer Price Rule ("MOPR") would likely exclude from the FCM new renewable resources developed pursuant to state statutes and regulations, and thereby result in customers being forced to purchase more capacity than is necessary for resource adequacy and proposed an alternative renewables exemption (the "Renewables Exemption Proposal"). In denying the Complaint, the FERC found that "NESCOE has failed to meet its burden under section 206 to demonstrate that ISO-NE's MOPR is unjust,

[6] *Id.* at P 19.

[7] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 146 FERC ¶ 61,039 (Jan. 24, 2014) ("*Jan 24 NEPGA FCM Admin Pricing Rules Order*"), *reh'g requested*.

[8] *ISO New England Inc.*, 146 FERC ¶ 61,038 (Jan. 24, 2014) ("*Jan 24 Exigent Circumstances Order*", and together with the *Jan 24 NEPGA FCM Admin Pricing Rules Order,* the *"Jan 24 Orders"*), *reh'g requested*.

[9] *Id.* at P 1.

[10] *New England States Comm. on Elec. v. ISO New England Inc.*, 142 FERC ¶ 61,108 (2013), *reh'g requested.*

unreasonable or unduly discriminatory" as applied to the New England Capacity Market.[11] The FERC declined to set the case for hearing, and therefore denied the motion to consolidate this proceeding with the FCA8 Revisions Compliance Filing proceeding (ER12-953),[12] on which it concurrently issued an order conditionally accepting in part and dismissing in part the ISO's proposed compliance filing. Rehearing was requested by NESCOE, the CT PURA, and the MA DPU on March 14, 2013. On March 29, 2013, NEPGA filed an answer challenging NESCOE's request for rehearing. On April 15, 2013, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Base ROE Complaint (2012) (EL13-33)**

On June 19, 2014, the FERC established hearing and settlement judge procedures[13] in response to the December 2012 Complaint by Environment Northeast ("ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"). As previously reported, the 2012 Base ROE Complaint challenged the TOs' 11.14% return on equity ("Base ROE"), and seeks a reduction of the Base ROE to 8.7%. In the *2012 Base ROE Initial Order*, the FERC found that the Complaint "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered."[14] The FERC rejected Complainants' request to consolidate this proceeding with the 2011 Base ROE Complaint, though it noted the change in its' practice for determining public utilities' ROE announced in that proceeding. Accordingly, the FERC directed the parties to present evidence and any discounted cash flow ("DCF") analyses in accordance with that guidance.[15] Hearing in this proceeding has been held in abeyance pending the outcome of settlement judge procedures. The parties have until June 24 to request a specific settlement judge. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaint (2011) (EL11-66)**

Also on June 19, 2014, the FERC issued *Opinion 531*,[16] affirming in part, and reversing in part, Judge Cianci's Initial Decision[17] in this proceeding. In *Opinion 531*, the FERC announced a new approach that it will use for determining public utilities' base ROE and a change in its' practice on post-hearing ROE adjustments. With respect to the New England TOs', the FERC applied its new that approach to the facts of this proceeding to determine the NETOs' base ROE, and established a paper hearing to allow the participants an opportunity to submit briefs on a limited issue regarding application of the new ROE approach.[18]

As previously reported, Trial Judge Cianci issued his initial decision on August 6, 2013 finding unjust and unreasonable the 11.14% ROE currently used in calculating formula rates for transmission service in the OATT, and finding that the ROE should be 10.6% for the October 2011 through December 2012 "locked in/refund period" and 9.7% from January 2013 forward, subject to further updating or modification by the

[11] *Id.* at P 32.

[12] *Id.* at P 30.

[13] *Environment Northeast, et al. v. Bangor Hydro-Electric Co.*, et al., 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*").

[14] *Id.* at P 26.

[15] *Id.*

[16] *Martha Coakley, Mass. Att'y Gen. et al.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*").

[17] *Martha Coakley, Mass. Att'y Gen. et al.*, 144 FERC ¶ 61,012 (2013) ("*Initial Decision*").

[18] *Opinion 531* at P 1.

FERC.[19] By way of reminder, the FERC established hearing and settlement judge procedures[20] following a complaint by a number of State, consumer, and consumer advocate parties (the "2011 Complainants")[21] seeking a FERC order reducing the 11.14% Base ROE to 9.2% "due to changes in the capital markets since the *Bangor Hydro* proceeding."[22] After settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful and terminated, these proceedings proceeded to now-completed hearings before Judge Cianci. Briefs on exceptions to the initial decision were filed by Complainants, TOs, EMCOS, and FERC Trial Staff on September 20. Briefs opposing exceptions were filed by the same parties on October 24, 2013.[23]

In *Opinion 531*, the FERC concluded that it is now appropriate to use the same two-step DCF methodology model for the electric industry as it has used for the natural gas and oil pipeline industries.[24] The FERC also made a tentative finding that the required long-term growth projection should be based on projected long-term growth in gross domestic product ("GDP"), but established a paper hearing to permit participants to present evidence on the appropriate long-term growth projection to be used in the two-step DCF methodology.[25] Applying the two-step DCF methodology to the facts of this proceeding, the FERC found that the TOs' starting proxy group was consistent with FERC precedent, and after taking official notice of the necessary GDP growth projections, the FERC's analysis produced a zone of reasonableness of from 7.03% to 11.74%.[26] Accordingly, the FERC that found it appropriate, based on record evidence, to place the TOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone (or at the two-thirds point), resulting in a 10.57% Base ROE (subject to adjustment based on the outcome of the paper hearing on long-term growth projections to be used).[27] The FERC also indicated that, based on the record in this proceeding and economic trends since 2008 more generally, it would end its practice of updating the ROE based on changes in U.S. bond yields during the proceeding.[28]

Challenges, if any, to *Opinion 531* must be filed on or before July 21, 2014. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[19] *Martha Coakley, Mass. Att'y Gen. et al.*, 144 FERC ¶ 61,012 (2013) ("*2011 Base ROE Initial Decision*").

[20] *Martha Coakley, Mass. Att'y Gen et al.*, 139 FERC ¶ 61,090 (2012) ("*Base ROE Complaint Order*"). The *Base ROE Complaint Order* was not challenged and is final.

[21] Complainants are Martha Coakley, Mass. Att'y Gen. ("MA AG"), the Conn. Public Utilities Regulatory Authority ("CT PURA"), Mass. Dep't of Pub. Utils. ("MA DPU"), New Hampshire Pub. Utils. Comm. ("NH PUC"), George Jepsen, Conn. Att'y Gen. ("CT AG"), CT OCC, Maine Off. of the Pub. Advocate ("ME OPA"), New Hampshire Off. of the Consumer Advocate, ("NH OCA"), Rhode Island Div. of Pub. Utils. and Carriers ("RI PUC"), Vermont Dep't of Pub. Srvc ("VT DPS"), MMWEC, AIM, TEC, Power Options, and the IECG.

[22] *See Bangor Hydro-Elec. Co. et al.*, 117 FERC ¶ 61,129 (2006) ("*Opinion 489*") at PP 79-81, *order on reh'g*, *Bangor Hydro-Elec. Co. et al.*, 122 FERC ¶ 61,265 (2008) at PP 30-34.

[23] Errata to the Table of Authorities were filed by Complainants and the TOs on Oct. 25 and 29, respectively.

[24] *Opinion 531* at P 8.

[25] *Id.*

[26] *Id.* at P 9.

[27] *Id.* at PP 9-10.

[28] *Id.* at P 11.

II. Rate, ICR, FCA, Cost Recovery Filings

- **Attachment F Implementation Rule Waiver Request (NHT) (ER14-1989)**

On June 9, 2014, the FERC granted the request by New Hampshire Transmission ("NHT") for a limited waiver of the Attachment F Implementation Rule, effective June 1, 2014.[29] The waiver allows NHT to exclude certain 2013 reliability planning expenses from the Operations and Maintenance Expense element of NHT's base PTF ATRR calculation for the June 1, 2014 RNS Rate and instead only include such amounts in the True-Up component of the transmission revenue requirement calculation. The FERC found that the one-time, one year waiver benefits ratepayers by preventing unnecessary fluctuations in the RNS Rate and will not adversely affect third parties.[30] Unless the NHT Order is challenged, with any challenges due on or before July 9, 2014, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Attachment F Implementation Rule Waiver Request (National Grid) (ER14-1686)**

On June 6, the FERC granted National Grid, on behalf of New England Power ("NEP"), waiver, in part, of certain provisions of Attachment F until January 12, 2015, effective June 8, 2014.[31] As previously reported, NEP requested a limited waiver of the Attachment F Implementation Rule (1) to permit NEP to provide estimated data as the basis for calculating its calendar year 2013 Transmission Revenue Requirements for the annual update of the RNS and TOUT rates that will be submitted to the FERC on or before July 31, 2014 and (2) to give NEP an additional 7 months (i.e. until February 28, 2015) to re-submit a corrected informational filing to the FERC with NEP's Transmission Revenue Requirement updated such that it fully complies with the OATT's requirement that 2013 FERC Form 1 data be used for calculating NEP's Transmission Revenue Requirement for calendar year 2014. In partially granting the waiver, the FERC found unsupported NEP's request for a waiver until February 18, 2015, and instead granted NEP a 105-day waiver, to January 12, 2015, providing the same number of days between the submittal of the delayed NEP FERC Form 1 filing and the delayed corrected informational filing, as there is between the usual FERC Form 1 filing and RNS informational filing.[32] In addition, the FERC insisted that

> ISO-NE stakeholders should be able to review the information underlying the 2014 Corrected Annual Update, including NEP's actual 2014 transmission revenue requirement, before it is filed with the Commission. NEP's Petition fails to provide for or address stakeholder review of the 2014 Corrected Annual Update, as Attachment F requires, and we see no reason to circumvent that opportunity. Therefore, in order to maintain Attachment F's provisions for stakeholder review, we will require NEP to post the proposed, 2014 Corrected Annual Update reflecting its actual 2014 transmission revenue requirement on ISO-NE's website for no less than 45 days prior to filing the 2014 Corrected Annual Update with the Commission. As a practical matter, if NEP submits its 2014 Corrected Annual Update on January 12, 2015, NEP must post its 2014 Corrected Annual Update on the ISO-NE's website no later than November 29, 2014 (i.e. 45 days from January 12, 2015).[33]

Unless the *NEP Waiver Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[29] *New Hampshire Transmission, LLC*, 147 FERC ¶ 61,193 (June 9, 2014) ("*NHT Order*").

[30] *Id.* at P 16.

[31] *Nat'l. Grid USA on behalf of New Eng. Power Co.*, 147 FERC ¶ 61,187 (June 6, 2014) ("*NEP Waiver Order*").

[32] *Id.* at P 11.

[33] *Id.* at P 13.

- **FCA8 Results Filing (ER14-1409)**

The results of the eighth FCA ("FCA8") held February 3, 2014 and filed February 28 remain pending before the FERC. In that filing, the ISO reported: (i) that the Capacity Zones for FCA8 are Connecticut, Maine, NEMA/Boston and Rest of Pool; (ii) FCA7 commenced with a starting price of $15.82/kW-mo. and concluded with a price of $14.99/kW-month (reset to $15.00/kW-mo.); (iii) FCA8 concluded with 33,702 MW of resources receiving CSOs to meet an ICR requirement of 33,855 MW (a 1,123 MW deficiency); (iv) administrative pricing rules set the prices for FCA8; (v) new resources that received a CSO in the Maine, Connecticut and Rest-of-Pool will be paid the $15.00/kW-mo. Capacity Clearing Price; existing resources, the $7.025/kW-mo. administrative price; (vi) both new and existing resources in NEMA/Boston (where the Carry Forward Rule was triggered) will be paid $15.00/kW-mo.; and (vii) no de-list bids were rejected for reliability reasons. The ISO asked the FERC to accept the FCA8 rates and results, effective June 28, 2014. On March 25, 2014, the ISO supplemented the FCA8 Results filing to include a Groton Wind CSO (9.751 MW summer; 19.771 MW winter) in Attachment A.

Comments on this filing and the March 25 supplement thereto were due on or before April 14, 2014. Interventions were filed by NEPOOL, CLF, Dominion, EPSA, Exelon, HQUS, NEPGA, NESCOE, NRG, and PSEG.

The following seven protests/adverse comments were filed:

- ***Joint Parties***[34] (requesting, as a result of what they assert is a flaw in the current Import-Constrained Capacity Zone Capacity Clearing Price Floor administrative pricing rule that resulted in an anomalous and unforeseen result, a one-time waiver to adjust the FCA8 results so that the capacity price in NEMA/Boston for *existing* resources for the 8th capacity commitment period is set at $10.00/kW-mo. (rather than $15.00/kW-mo.); and an order directing a stakeholder process to consider any necessary changes to the Import-Constrained Capacity Zone Capacity Clearing Price Floor rule to prevent the potential for unjust and unreasonable results for any future auctions);
- ***EMCOS***[35] (requesting the FERC set aside the FCA8 results because those results are "affected by market manipulation, the unilateral exercise of market power, and the operation of a market process deficient in the fact that it failed to permit any supply response to the announcement of a permanent withdrawal of capacity from the Forward Capacity Market." To the extent the FCA8 results are not set aside, EMCOS requested an evidentiary hearing and investigation addressing market manipulation and the exercise of market power and, like Joint Parties, requested a waiver of the Market Rule provisions that set the prices for capacity located in NEMA/Boston so that the FCA8 NEMA/Boston default price is re-set to no higher than $10/kW-mo.);
- ***CT AG*** (urging the FERC to not accept the FCA8 Results Filing until it, through the Office of Enforcement ("OE"), has investigated whether the rates were "the result of abuse of market power and, therefore, unjust and unreasonable");
- ***CMEEC/NHEC*** (requesting that the FERC, to the extent it accepts the FCA8 results, "initiate an expeditious investigation into whether the auction outcome is (1) reflective of legitimate and appropriate market actions undertaken in accordance with reasonable regional market rules or (2) the product of impermissible economic withholding");
- ***State Advocates***[36] (noting concern, based on Synapse Energy Economics analysis, that Brayton Point retirement and withdrawal from FCA8 may have been an unlawful exercise of market power,

[34] "Joint Parties" are National Grid, MA AG, MA DPU, the Northeast Utilities Companies ("NU"), and the United Illuminating Co. ("UI").

[35] In this proceeding, "Eastern Massachusetts Consumer-Owned Systems" or "EMCOS" are Belmont, Braintree, Concord, Georgetown, Groveland, Hingham, Littleton (MA), Merrimac, Middleton, Rowley, Taunton, and Wellesley.

[36] "State Advocates" are the New Hampshire Office of Consumer Advocate, Maine Office of the Public Advocate, and the Connecticut Office of Consumer Counsel.

requesting FERC, including Staff and OE, further review the FCA8 results and, if any exercise of market power is found to have occurred, directing the ISO to make Market Rule changes to prevent any such exercise of market power in future FCAs);

- ***Public Citizen, Inc.***[37] (asserting that Energy Capital Partners "likely closed its Brayton Point generation units not because of environmental compliance problems or uneconomic operations, but rather to "earn more money by obtaining capacity auction payments at its 5 other New England-area power plants then if Brayton Point continued to operate", urging the FERC to "nullify the results of the FCA8 auction and investigate Energy Capital Partners for violation of the Commission's rules", and, if ECP was indeed in violation of the Commission's rules, demanding revocation of ECP's market based rate authority); and
- ***UWUA Local 464***[38] (urging the FERC to reject the FCA8 results filing and direct an investigation by the Office of Enforcement, alleging ECP knowingly and uneconomically withheld Brayton Point from FCA8 in order to intentionally inflate market prices to benefit its other New England assets).

On April 25, Brayton Point responded to the allegations made against it by parties in this proceeding. On April 28, Public Citizen responded to Brayton Point's answer. On April 29, answers to pleadings submitted were filed by NEPOOL, the ISO, Dominion, and NEPGA/EPSA. Answers to those pleadings were filed by Dominion (to UWUA Local 464), Public Citizen (to Brayton Point), and Joint Parties (to the three April 29 pleadings). Since the last Report, UWUA Local 464 filed on June 10 an answer to Brayton Point's April 25 pleading. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663. slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order[39] that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding[40] for further consideration, which remains to be acted on. In particular, the FERC must (i) determine whether PSEG's position (that it should receive the full (unprorated) floor price for all its resources that it could not prorate) would be an appropriate way to interpret the then-existing Market Rules and, if not, (ii) respond to PSEG's objections that any contrary result would result in "undue discrimination" and would be "inconsistent with the fundamental policy goals" of FCM. On October 15, 2012, PSEG filed a motion requesting that the FERC issue an order on remand directing the ISO to pay PSEG the full FCA floor price without further delay (for PSEG, the difference totaling $2.8 million plus interest). The ISO filed on October 31, 2012 an answer to PSEG's October 15 motion. On November 1, 2012, Connecticut Generators[41] submitted comments supporting PSEG's request and a few of the Connecticut Generators moved to intervene out-of-time. As noted, this matter remains pending before the FERC.

[37] Public Citizen, Inc. is a national, nonpartisan consumer advocacy nonprofit organization based in Washington, DC. Public Citizen states that it represents the interests of "more than 350,000 members and supporters across the United States. Our members and supporters are households impacted by the actions of the owners of generation and power marketers in FERC-jurisdictional markets, and by the design and governance of FERC-jurisdictional markets".

[38] The Utility Workers Union of America Local 464 ("UWUA Local 464") is a local labor organization located in Somerset, Massachusetts, whose approximately 140 members are employed at the Brayton Point Power Station.

[39] *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[40] *ISO New England Inc.*, 123 FERC ¶ 61,290 (June 20, 2008); *reh'g denied*, 130 FERC ¶ 61,235 (Mar. 24, 2010), *remanded*, *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[41] "Connecticut Generators" are CP Energy Marketing (US) Inc. and Bridgeport Energy LLC (collectively, "Capital Power"); Dominion Resources Services ("Dominion"); Milford Power Co. and EquiPower Resources Management (collectively, "EquiPower"); NRG Power Marketing, Conn. Jet Power, Devon Power, Middletown Power, Montville Power, Norwalk Power, and Somerset Power (collectively, "NRG"); and PPL EnergyPlus.

- **ISO Securities: Capital Expenditures Refinancings (ES13-34)**

On June 17, the ISO filed a "Report of Securities Issued" in connection with the Jul 31, 2013 order authorizing the ISO to issue up to $39 million in senior unsecured notes[42] in order to refinance the aggregate principal amount of senior notes previously authorized and issued.[43] If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Section 12 LOLE Demand Curve Changes (ER14-2153)**

On June 9, the ISO and NEPOOL jointly filed changes to Market Rule 1 Section 12 that address the calculation of certain parameters that define the shape of the sloped demand curve, as well as making several additional clarifying and clean-up changes ("Section 12 Demand Curve Changes"). Specifically, the Section 12 Demand Curve Changes address the ISO calculation of demand curve capacity requirements factoring in additional Loss of Load Expectation ("LOLE") values of 1-in-5 and 1-in-87 days/year. The additional capacity requirement values will be calculated using the same modeling methods, assumptions and calculations as are currently used to calculate the Installed Capacity Requirement ("ICR") and will be reviewed with stakeholders and filed with the Commission using the same process currently used for determining and filing the annual ICR prior to each FCA. A September 1, 2014 effective date was requested. The Section 12 Demand Curve Changes were unanimously supported by the Participants Committee by way of the June 6 Consent Agenda. Comments on the Section12 Demand Curve Changes are due on or before June 30. If you have any questions, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Identification of Potential New SEMA/RI Capacity Zone Boundary (ER14-1939)**

As previously reported, the FERC accepted, on May 29, materials filed by the ISO that identified a potential new boundary for a Southeastern Massachusetts/Rhode Island ("SEMA/RI") Capacity Zone. As explained in the ISO filing, Section III.12.3 of the Tariff requires the ISO to file, pursuant to FPA Section 205, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones (the process used by the ISO to identify potential new Capacity Zones and boundaries is specified in Section 3.1 of Attachment K to the OATT). Following scenario analyses, which identified certain transmission constraints and associated transfer limits on or near the interface of the boundary formed by the combined existing SEMA and RI Load Zones, the ISO identified a new boundary for a potential SEMA/RI Capacity Zone. The ISO indicated that the SEMA and RI Load Zones would remain separate Load Zones for Energy Market and related purposes. Whether the potential zone will actually be modeled as a separate import-constrained Capacity Zone in FCA 9 will be addressed in a pre-FCA9 informational filing to be made by the ISO pursuant to Tariff Section III.13.8.1(a) in early November 2014. The changes were accepted as of May 30, 2014, as requested.[44] Unless the May 29 order is challenged, with any challenges due on or before June 30, this proceeding will be concluded. If you have any questions, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Curve Changes (ER14-1639)**

As previously reported, the FERC conditionally accepted on May 30, 2014, the April 1 revisions to the FCM rules jointly submitted by the ISO and NEPOOL that establish a system-wide sloped demand curve

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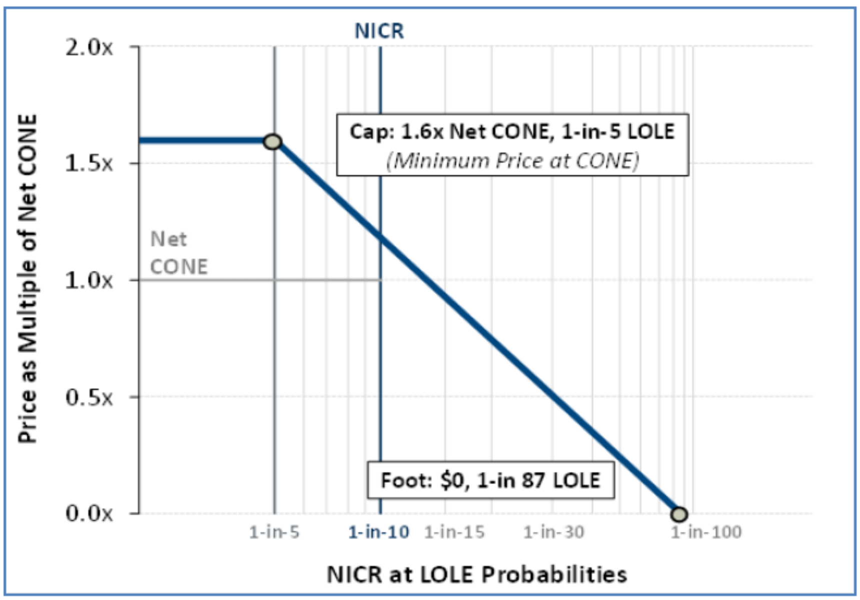
[42] *ISO New England Inc.*, 144 FERC ¶ 62,087 (2013).

[43] *See ISO New England Inc.*, 109 FERC ¶ 62,195 (2004); *ISO New England Inc.*, 140 FERC ¶ 62,173 (2012).

[44] In light of the timing of the May 29 order, no waiver was required to facilitate the potential modeling of the SEMA/RI Capacity Zone in FCA 9.

("Demand Curve Changes").[45] The Demand Curve Changes define the shape of the system-wide sloped demand curve (with key points defined by CONE and the 0.1 days/year LOLE target) illustrated below, extend the period during which a Market Participant may "lock-in" the capacity price for a new resource from five to seven years, establish a limited renewables, and eliminate, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct. In accepting the Demand Curve Changes, the FERC found:

> the proposed demand curve design reasonably balances the multiple considerations identified by Filing Parties, including reducing price volatility, susceptibility to the exercise of market power, frequency of low reliability events, and avoiding falling below a 1-in-5 LOLE in any individual time period. We further find that the sloped demand curve represents an important improvement to the FCM, as it will address some of the challenges presented by the use of a vertical demand curve in previous auctions, including, among other things, the Commission's concerns regarding price volatility and the administrative pricing provisions, as raised in the January 24, 2014 Order.[46]



Having found the Demand Curve Changes just and reasonable, the FERC indicated that it "need not consider alternative designs. To the extent parties sought additional changes, [the FERC encourage[d] them to do so through the stakeholder process."[47]

The Demand Curve Changes were accepted effective June 1, 2014, as requested, for implementation prior to associated FCA9 deadlines. As a condition to its acceptance, the FERC directed the ISO, in a 60-day compliance filing, to clarify how new resources could qualify for the Renewable Technology Resources MOPR exemption in future auctions.[48] That filing is due on or before July 29, 2014. Challenges, if any, to the *Demand Curve Order* are due on or before June 30, 2014.

If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCA9 ORTP Rules for On-Shore Wind and DR with DG (ER14-1477)**

As previously reported, the FERC accepted in part, and rejected in part, revisions jointly submitted by the ISO and NEPOOL on March 13 in this proceeding.[49] The FERC accepted a recalculated ORTP for FCA9 for on-shore wind resources ($10.32/kW-mo. after removing the Production Tax Credit ("PTC")) and Demand

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[45] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*").

[46] *Id.* at P 29.

[47] *Id.* at P 35.

[48] *Id.* at P 88.

[49] *ISO New England Inc.*, 147 FERC ¶ 61,109 (May 12, 2014).

Resources ("DR") with Distributed Generation ("DG") (for DR with new DG, an ORTP value based on the ORTP of a newly installed generator of the same technology type; for DR with previously installed DG, $1.145/kW-mo. -- the ORTP value for Load Management) ("ORTP Revisions"). The ORTP Revisions were accepted May 13, 2014, as requested. However, the FERC rejected proposed revisions that would have required the IMM to consider any reinstatement of the PTC when the IMM performs an annual update of the ORTP value for on-shore wind resources, noting a concern that such a requirement would require the IMM to subjectively interpret federal tax law, potentially resulting in a significant change to the ORTP for an onshore wind resource without FERC or stakeholder review.[50] The FERC directed the ISO to submit a compliance filing on or before June 11 to remove the rejected Tariff language.

Compliance Filing. On June 9, the ISO and NEPOOL submitted that compliance filing, striking the FERC-rejected tax credit adjustment for on-shore wind. The compliance changes were unanimously supported by the Participants Committee at its June 6 meeting. Comments on the compliance filing, if any, are due on or before June 30. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NCPC Payment Re-Design and Conforming Mitigation Changes (ER14-1147)**

On January 24, the ISO and NEPOOL jointly submitted revisions to Appendices A & F to Market Rule 1 and to the unified Definitions Section of the Tariff (the "NCPC Credit Revisions") to redesign the NCPC credit rules and to make conforming changes to the market mitigation provisions of Appendix A. Specifically, the NCPC Credit Changes were revised to account for the Energy Offer Flexibility Changes (*see* ER13-1877 below) and to unify the NCPC credit rules under an enhanced design principle. A December 3, 2014 effective date, for implementation with the Offer Flexibility Changes, was requested. The NCPC Credit Revisions were supported by the Participants Committee at the November 8, 2013 meeting. Comments on this filing were due on or before February 14, 2014. Doc-less interventions were filed by Brookfield, Dominion and NU; no comments were submitted. This matter is currently pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Performance Incentives Jump Ball Filing (ER14-1050)**

As previously reported, the ISO and NEPOOL submitted on January 17, 2014, two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England -- the "ISO-NE Proposal" and the "NEPOOL Proposal". Both Proposals sought to further address existing reliability, investment and resource performance challenges in New England. However, the two proposals offered fundamentally different approaches. The ISO-NE Proposal would redefine capacity as a different product where payments are affected by whether a resource is providing energy and/or operating reserves in Real-Time three years hence. Through its "pay-for-performance" mechanism, the ISO Proposal abandoned longstanding capacity market principles in New England and the other RTO markets and converts the FCM from a market designed to ensure long-term resource adequacy to one that is driven primarily by prospective and largely unpredictable actual production. Resources not producing energy or reserves at the time of a "Capacity Scarcity Condition" for any reason would be subject to significant penalties, even if that scarcity condition occurs during very low load conditions, or is caused by transmission outages or even by errors in the ISO's load forecasting. The NEPOOL Proposal, in contrast, built upon a series of Market Rule changes, either made or are pending, proposed changes that would enhance the current market design and achieved the objective of improving the performance incentives for resources in the ISO-NE electricity markets. The Proposals were submitted pursuant to "jump ball provision" of the Participants Agreement (Section 11.1.5).

On May 30, 2014, the FERC issued an order in response to the jump ball filing.[51] As more fully summarized in the May 31 memorandum circulated to the Committee and posted on the NEPOOL website (http://www.nepool.com/Litigation_Reports.php), the FERC concluded that the existing Tariff, specifically the

[50] *Id.* at P 22.

[51] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014) ("*PI Order*").

current FCM payment design, "is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits" and instituted a proceeding under section 206 of the FPA (*see* EL14-52-000 in Section I above). Concluding that neither the ISO-NE Proposal nor the NEPOOL Proposal, standing alone, had been shown to be just and reasonable, the FERC, drawing features from each Proposal, went on to direct the ISO to submit by July 14, 2014 Tariff revisions reflecting a modified version of the ISO-NE Proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's Proposal. Specifically, the compliance filing is to include (1) changes to implement ISO-NE's proposed two-settlement capacity market design with certain modifications, and (2) changes to increase the RCPF values for 30-minute operating reserves to $1,000/MWh and for 10-minute non-spinning reserves to $1,500/MWh. The FERC established a refund effective date, which will be the date on which the June 3 notice of the Section 206 proceeding (EL14-52) is published in the *Federal Register*.

As indicated more fully in the materials for the Summer Meeting, there will be an opportunity for the Committee to discuss and, if and to the extent appropriate, take action on, the implications of the *PI Order* (see Agenda Item #12B). Links to all of the documents filed in this proceeding (other than interventions) can be found on the NEPOOL website at http://nepool.com/ER14-1050.php.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Response Baseline Changes (ER14-727)**

As previously reported, the FERC conditionally accepted, effective June 1, 2014, revisions to Market Rule 1 and Appendix E1 (the "DR Baseline Changes") to improve baseline accuracy by accounting for scheduled and forced curtailments of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets (typically industrial or commercial facilities).[52] As previously reported, the DR Baseline Changes address the potential distortion of baselines due to scheduled or forced curtailments by requiring demand response ("DR") providers to submit meter data values during a curtailment that are equal to the last unadjusted baseline computed prior to the curtailment instead of actual meter readings. The DR Baseline Changes also provide that a DR provider may not submit a Demand Reduction Offer during a scheduled or forced curtailment since the affected assets are not actually available to be dispatched in order to balance Real-Time supply and demand. In accepting the DR Baseline Changes, the FERC found that the Changes improve the accuracy of and preserve Demand Response Baselines during periods of forced and scheduled curtailments, provide for a more accurate representation of asset availability for dispatch and appropriate compensation, and the other proposed clarifications just and reasonable.[53] The FERC conditioned its acceptance of the DR Baseline Changes on (i) further explanation (or Tariff changes) explaining how a Demand Response Asset with a cleared Demand Reduction Offer that experiences an unanticipated forced curtailment during the period in which it was scheduled to reduce load, will receive an energy payment, and (ii) a correction to Market Rule Section 13.7.1.5.10.2(a)(ii).[54] The April 1 order was not challenged and is final and unappealable.

In an April 3 memo to the Markets Committee, the ISO indicated that it would not propose any Market Rule changes in response to the April 1 order and provided an explanation as to how the previously proposed Tariff language provides for energy payments to a Demand Response Asset with a cleared Demand Reduction Offer during the period in which it was scheduled to reduce demand on the first day of an unanticipated forced

[52] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,006 (Apr. 1, 2014).

[53] *Id.* at P 5.

[54] *Id.* at P 6.

curtailment.[55] The compliance filing directed was submitted by the ISO on May 1. Comments on the compliance filing were due on or before May 22; none were filed and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)**

Requests for rehearing and clarification of the *Jan 24 Exigent Circumstances Order* in this proceeding remains pending. As previously reported, the FERC accepted, on January 24, revisions to the FCM administrative pricing rules that (i) addressed what the ISO identified as a "gap" in the Insufficient Competition rules; (ii) set an administrative rate of $7.025/kW-month to be applied if there is Insufficient Competition (as the ISO proposed to redefine it) or Inadequate Supply in FCA8; and (iii) made additional clarifying changes to the FCM administrative pricing rules (collectively, the "FCM Pricing Rule Changes").[56] The FCM Pricing Rule Changes became effective January 24, 2014, as requested.

In accepting the filing, the FERC established a $7.025/kW rate, should the administrative pricing provisions trigger, for FCA8, replacing existing Tariff provisions that it found unjust and unreasonable in the Administrative Pricing Rules Complaint order (*see* EL14-7 in Section I above).[57] Addressing the ISO's statements about a sloped demand curve as a long-term solution to the issues presented in this proceeding, the FERC, noting its concerns that waiting until this summer for such a proposal to be filed would not allow sufficient time for implementation by FCA9, the FERC stated

> Given ISO-NE's explanation that a sloped demand curve will address the difficult and challenging issues presented here, and based on ISO-NE's statements that its proposal here is intended to be temporary and address concerns for FCA8, we will direct ISO-NE to submit its proposed demand curve by April 1, 2014, to allow sufficient time for implementation prior to FCA9.[58]

Demand Curve Changes were filed by April 1 as directed and accepted (ER14-1639 above).

Also in response to the *Jan 24 Exigent Circumstances Order*, the ISO and NEPOOL jointly filed, on March 25, a revised Section III.13.2.8.2 to Market Rule 1 to clarify the precedence of the Inadequate Supply rule over the Insufficient Competition rule in the event that both conditions are triggered simultaneously. That change was unanimously supported by the Participants Committee at the March 21 meeting. Comments on the March 25 compliance filing were due on or before April 15, 2014; none were filed. The March 25 compliance filing is pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[55] The ISO's memo is available with the April 8 Markets Committee materials at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/apr82014/a_09_iso_memo.pdf.

[56] *Jan 24 Exigent Circumstances Order*.

[57] The order also accepted the ISO's proposed changes to correct the IC Gap and the remaining administrative pricing provisions. Addressing the questions concerning the "Exigent Circumstances" underlying the filing, the FERC found that the ISO had satisfied the prescribed criteria for an Exigent Circumstances filing: "ISO-NE justifiably determined that failing to immediately implement a change prior to FCA 8 could affect the short-term competitiveness and efficiency of the markets and, in the long-term, affect system reliability." *Id.* at P 52.

[58] *Id.* at P 30.

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

As previously reported, the FERC, on February 12, 2013, conditionally accepted in part, and rejected in part, revisions to the FCM and FCM-related rules in the Tariff ("FCA8 Revisions") filed by the ISO and the PTO AC.[59] The *FCA8 Revisions Order* accepted the following aspects of the FCA8 Revisions as compliant with its prior FCM Orders: the ISO's offer review trigger prices;[60] unit specific offer review;[61] the ISO's proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports' treatment under MOPR;[62] no exemptions to MOPR for new Self-Supplied Resources;[63] the application of mitigation to *all* new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;[64] \$1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;[65] and a number of other additional revisions.[66] The *FCA8 Revisions Order* rejected: the ISO's proposed methodology for reducing the offer floor of an uncleared resource that has already achieved commercial operation at the time of an FCA (directing the ISO to submit a revised proposal that subjects a resource to an offer floor until it has demonstrated that it is needed by the market);[67] and the ISO's request to model only 4 capacity zones for FCA8 (the ISO's Capacity Zones Changes were accepted in *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014)). Two requests for rehearing of the *FCA8 Revisions Order* were filed on March 15, 2013, one by MMWEC, NHEC, APPA, NEPPA, and NRECA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MMWEC *et al.* request. On April 15, 2013, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 784* Compliance Filing (ER14-877)**

As previously reported, the ISO submitted a compliance filing on December 27, 2013, in response to *Order 784*. In its December 27 filing, the ISO explained how the Tariff's deviations from the FERC's *pro forma* Open Access Transmission Tariff ("OATT"), including the Regulation Market Rules, already meet the requirements and policy goals of *Order 784* and therefore meet the FERC's requirements for a showing of provisions that are "consistent with or superior to" the *pro forma* OATT. In addition, the ISO asked for a waiver of the new requirement to post on its OASIS historical one-minute and ten-minute certain Area Control Error data for the most recent calendar year, and to update this posting once per year. Interventions were filed by NEPOOL, Exelon and NU. No comments on this filing were submitted on or before the January 17, 2014 comment date. This matter is pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[59] *ISO New England Inc.*, 142 FERC ¶ 61,107 (Feb. 12, 2013) ("*FCA8 Revisions Order*").

[60] *FCA8 Revisions Order* at PP 37-38.

[61] *Id.* at P 53.

[62] *Id.* at P 70.

[63] *Id.* at P 80.

[64] *Id.* at P 97.

[65] *Id.* at P 126.

[66] *Id.* at P 127.

[67] *Id.* at PP 63-64.

- ***Order 764* Compliance Changes (ER14-375)**

As previously reported, the FERC, on March 20, 2014, accepted in part and rejected in part the revisions filed November 12, 2013 by the ISO, NEPOOL, the PTO AC, CSC, and the Schedule 20A service providers ("SSPs") to comply with the requirements of *Orders 764* and *764-A* (the "*Order 764* Compliance Changes").[68] While the FERC accepted the changes to the LGIA that use "Intermittent Power Resource" and "System Operator" rather than the *pro forma* Tariff terms,[69] the FERC rejected the proposal to place the details of meteorological and forced outage data reporting requirements in OP-14, rather than in Appendix C of the LGIA (concerned that the could "unilaterally change those reporting requirements without having to make at least some showing that the change is just and reasonable").[70] Accordingly, the FERC directed the ISO to submit an additional compliance filing on or before April 21 that places the details of VERs' meteorological and forced outage data reporting requirements found in OP-14 (which it otherwise found satisfies the substantive reporting requirements of *Order 764*) in Appendix C of the LGIA in the Tariff.[71]

On April 21, 2014, the ISO and the PTO AC submitted changes in response to the March 20 order. Those changes revise LGIA Article 8.4 to cross-reference LGIA Appendix C, which contains a new subsection that incorporates the specific meteorological and forced outage data reporting requirements set out in the Wind Operators Guide and the means by which that data is to be supplied to ISO-NE. New LGIA Appendix C.3 specifies the meteorological and forced outage data requirements for an Interconnection Customer with a Small Generating Facility that is an Intermittent Power Resource having wind as the energy resource. Implementation details continue to reside in the Wind Operators Guide. The Transmission Committee unanimously recommended Participants Committee support for the compliance changes at a special April 15 meeting. The changes will be considered as part of the May 2 Consent Agenda (Item No. 4). Comments on the compliance filing were due on or before May 12; none were filed. The compliance filing is currently pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000* Interregional Compliance Filing (ER13-1960; ER13-1957)**

On July 10, the ISO, NEPOOL and the PTO AC jointly filed revisions to Sections I and II of the Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* (the "*Order 1000* Interregional Compliance Changes") (ER13-1960). In addition, the ISO, on behalf of itself, NYISO and PJM, filed an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Amended Protocol") as part of its compliance changes (ER13-1957). The *Order 1000 Interregional Compliance Changes* include (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I. The *Order 1000* Interregional Compliance Changes and the Amended Protocol were supported by the Participants Committee at its June 27 Summer Meeting. On August 7, the FERC extended the comment deadline on these filings to and including September 9, 2013. Doc-less motions to intervene were filed by a number of New England parties in both proceedings, including Dominion, Exelon, PPL, PSEG, and NEPOOL (in the Protocol proceeding (in which it was not a filing party)). On August 26, NEPOOL filed comments supporting the Protocol. NEPOOL added that "From a stakeholder perspective, stakeholder input into revisions to the Protocol as it evolves over time would be easier and more likely to be taken into account if it were made part of the individual regional tariffs of each of the Northeast ISOs rather than existing solely as a stand-alone three-party agreement". On September 9, NESCOE submitted comments generally supporting the filings, but reserving the right to further comment on these filings should the substance of the changes be modified as a result of further FERC (*see* ER13-193 and ER13-196 below) or federal court

[68] *ISO New England Inc. and New England Power Pool Participants Comm.*, 146 FERC ¶ 61,190 (Mar. 20, 2014).

[69] *Id.* at P 30.

[70] *Id.* at P 31.

[71] *Id.* at P 32.

proceedings. Public Interest Organizations[72] raised concerns that the Protocol and related amendments "do not meet certain of the transparency and cost allocation aspects of [*Order 1000*]'s minimum requirements." On September 24, the ISO answered Public Interest Organizations' and NEPOOL's comments. These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000* Compliance Filing (ER13-193; ER13-196)**

Rehearing of the FERC's May 17, 2013 order on the region's *Order 1000* compliance filing[73] (described in previous Reports) remains pending. As previously reported, the *Order 1000 Compliance Order* accepted the ISO-NE/PTO compliance filing as partially complying with *Order 1000,* but required changes to the compliance proposal. The primary change was the elimination of the Right of First Refusal ("ROFR") and the establishment of competitive transmission development for all regional transmission projects (with an exception to the elimination of the ROFR for transmission needed for reliability within three years of the needs assessment determination and subject to certain other limiting criteria). Additionally, the *Order 1000 Compliance Order* required that the public policy transmission proposal be revised to: (i) make the ISO, rather than the New England states, the entity that evaluates and selects which transmission projects will be built to meet transmission needs driven by public policy; and (ii) include an *ex ante* default cost allocation method, transparent to all stakeholders, developed in advance of particular transmission facilities being proposed, rather than leaving it to the states to decide cost allocation on a project-specific basis after particular projects are proposed. While requiring these fundamental changes to the public policy transmission part of the filing, the *Order 1000 Compliance Order* also allowed for the NESCOE-driven proposal for both selection of projects and cost allocation to remain in the tariff as a complementary process for voluntary transmission projects alongside the *Order 1000*-compliant process. A more detailed summary of the *Order 1000 Compliance Order* was circulated to the Participants Committee on May 20, 2013. On June 17, the ISO, LS Power, PTO AC and NESCOE each filed requests for clarification and/or rehearing of the *Order 1000 Compliance Order*. On June 28, the ISO answered LSP Power's request concerning the effective date for the *Order 1000* compliance changes. On July 16, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

Order 1000 November 15 Compliance Order Changes. On November 15, the ISO and the PTO AC jointly submitted proposed revisions to Sections I and II of the Tariff and to the Transmission Operating Agreement ("TOA") (the "Compliance Revisions") to comply with the FERC's May 17, 2013 *Order 1000 Compliance Order*. The revisions included planning revisions (addressing competitive processes for developing new regional transmission projects), cost allocation revisions (regarding the allocation of costs for Public Policy Transmission Projects), and TOA revisions. The Planning Revisions and the Cost Allocation Revisions filed by the ISO and PTO AC were considered but not supported by the Participants Committee at its November 8 meeting.

Comments on the November 15 filing were filed by ***NEPOOL*** (seeking two sets of changes to the Planning Revisions filed by the ISO and PTO AC (i) limiting the scope of transmission projects that are grandfathered under the old, non-competitive processes, so that Proposed Projects are not grandfathered but instead are open to competition; and (ii) ensuring that all Qualified Transmission Project Sponsors ("QTPS") are on an equal footing regarding consulting with the ISO in assessing regional transmission needs and solutions (together, the "NEPOOL Alternative"); but taking no position on the Cost Allocation revisions); ***CLF and The Sustainable FERC Project*** (supporting the November 15 filing and its public policy planning and regional cost allocation provisions.); EMCOS/Participating Municipals (request the ISO and TOs be required to revise Section 3.3 of Attachment K to eliminate the grandfathering for proposed Transmission Projects, and to revise Schedule 12 to ensure that public power systems not subject to state Public Policy

[72] "Public Interest Organizations" are Conservation Law Foundation, Environment Northeast, Natural Resources Defense Council, Pace Energy and Climate Center, and the Sustainable FERC Project.

[73] *ISO New England Inc.*, 143 FERC ¶ 61,150 (May 17, 2013) ("*Order 1000 Compliance Order*").

requirements are exempted from any obligation to pay for Public Policy projects); ***Environmental Groups***[74] (each supporting the Cost Allocation Revisions, but noting continuing concern that the region's planning process fails to produce more cost-effective and efficient planning outcomes); ***LSP Transmission*** (supporting NEPOOL's Alternative, requesting a January 1, 2014 effective date for the compliance filing, and protesting the hold harmless provision contained in Attachment O, Section 9.01, the ISO's evaluation process and the proposed study deposit), ***MA DPU*** (supporting the Cost Allocation Revisions); ***NESCOE*** (without expressing a position on the Cost Allocation Revisions, affirming its support for NESCOE it having a central role in determining how public policy planning need relates to cost allocation); ***New Hampshire Transmission*** ("NHT") (protesting the November 15 filing and suggesting specific amendments to the proposal to be submitted a short time after an order on the second compliance filing is issued); ***Public Systems***[75] (requesting that the FERC adopt MMWEC's cost allocation proposal and direct the Filing Parties to include an express right of consumer-owned utilities to opt out of the non-regional allocated costs of projects satisfying policy requirements that do not apply to them); and ***VT/RI Parties***[76] (protesting the Cost Allocation Revisions). Answers to the protests and comments were filed on January 15 by the ISO, PTO AC, and MA DPU (to the VT/RI Parties). On February 4, NHT filed an answer to the January 15 answers by the ISO and PTO AC. The ISO answered the NHT February 4 answer on February 18.

These matters are pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NU: GSRP Localized Costs Allocation (ER14-2064)**

As previously reported, NU filed on May 30, 2014, revisions to Schedule 21-NU to allocate the Localized Costs in Connecticut ($3.3 million) and Massachusetts ($14.3 million) associated with the Greater Springfield Reliability Project to load in those states. In addition, NU filed changes to (i) revise and update the *pro forma* Localized Costs Responsibility Agreement set forth as Attachment NU-E to Schedule 21-NU; (ii) modify the tariff provisions regarding the recovery of Localized Costs during the initial term for Localized Facilities; (iii) make certain clarifications to the tariff language; and (iv) delete tariff provisions that are no longer applicable. Comments supporting this filing were submitted by CT PURA and National Grid; comments protesting the filing, jointly by the MA AG and AIM. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304)**

As previously reported, the FERC accepted on September 24, 2012, the revised schedules and notices of cancellation filed by Green Mountain Power ("GMP") in this proceeding, but suspended the provisions, subject to

[74] "Environmental Groups" are Environment Northeast, Connecticut Fund for the Environment, Environment Council of Rhode Island, Health Care Without Harm, The Natural Resources Council of Maine, and The Sustainable FERC Project.

[75] In this proceeding, "Public Systems" are MMWEC and NHEC.

[76] "VT/RI Parties" are the State of New Hampshire Public Utilities Commission ("NHPUC"), the Rhode Island Public Utilities Commission ("RIPUC"), the Vermont Public Service Board ("VT PSB"), the Vermont Public Service Department ("VPSD"), Vermont Electric Power Company ("VELCO"), and Vermont Transco ("VT Transco").

refund, and established hearing and settlement judge procedures.[77] In its September 24 order, the FERC stated that its "preliminary analysis indicates that Applicants' proposed Schedules 21-GMP and 20A-GMP and notices of cancellation have not been shown to be just and reasonable, and … raise issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed in the hearing and settlement judge procedures we order."[78] Requests for clarification and/or rehearing of the *GMP Merger Order* requested by VEC and WEC ("Cooperatives")[79] were denied on February 25, 2013.[80] Also on February 25, the FERC accepted GMP's October 31, 2012 compliance filing, rejecting Cooperatives' arguments protesting the compliance filing as beyond the scope of the compliance filing proceeding.[81]

Judge Karen V. Johnson was designated as the settlement judge, and convened two settlement conferences. After a lengthy period of reported negotiation, Green Mountain Power Corporation ("GMP") submitted on November 13 a Settlement Agreement and Offer of Settlement ("Settlement") that reportedly resolves all disputes in these proceedings. Pursuant to a December 2 notice issued by Judge Johnson, the deadline for filing initial comments was December 13, 2013; the deadline for filing reply comments, December 23, 2013. FERC Staff filed comments on December 13 indicating that it did not oppose certification or approval of the settlement. Judge Johnson certified the uncontested settlement to the Commission on March 24, 2014.[82] On April 4, 2014, Chief Judge Wagner issued an order terminating settlement judge procedures. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP Annual Informational Filing (ER12-2304)**

On May 30, 2014, pursuant to Section 4 of Schedule 21-GMP, GMP submitted its annual informational filing containing the true-up recalculation of its costs for the January 1,2013 through December 31, 2013 time period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VEC and 20-VEC Annual Informational Filing (ER10-1181)**

On May 21, 2014, VEC submitted its annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 2014 – June 30, 2015 period. VEC indicated that it was not proposing any changes to the underlying formulas. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**

On May 30, 2014, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2013 through December 31, 2013. NSTAR stated that the filing

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[77] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.*, 140 FERC ¶ 61,239 (Sep. 24, 2012) ("*GMP Merger Order*"), *reh'g denied*, 142 FERC ¶ 61,146 (Feb. 25, 2013).

[78] *Id.* at PP 21-22.

[79] Cooperatives asserted that the FERC failed to appropriately address the Mobile Sierra claim contained in VEC's Protest and further explained in WEC's Answer. WEC separately requested that the FERC correct three statements in the *GMP Merger Order* concerning positions taken by WEC.

[80] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.,* 142 FERC ¶ 61,146 (2013).

[81] *Green Mountain Power Corp.*, 142 FERC ¶ 61,147 (Feb. 25, 2013). The FERC noted that Cooperatives' raised the same issues in their joint request for rehearing of the *GMP Merger Order*, submitted in Docket No. ER12-2304-001, and their arguments will be addressed in that proceeding. *Id.* at n. 7.

[82] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.,* 146 FERC ¶ 63,025 (Mar. 24, 2014).

complies with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement previously approved by the FERC.[83] The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2014 Q1 (ER14-1954)**

On June 9, the FERC accepted the ISO's Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2014 (the "Report"). The ISO is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Highlights include the following new projects: NX9/NX12D Data Integration and Automation Phase II ($1 million); Voltage Stability ($898,300); Auction Improvements ($383,800); and Passive Asset Data Repository ($78,900). Projects reported to have significant changes include decreases in (i) Business Continuity Plan Infrastructure Enhancements Phase III (by $463,200, reflecting resource allocation to other projects); (ii) CTS (by $456,000 (deferred to 2015); and (iii) System Improvement Requests (by $500,000 due to reduced resources available). Unless the June 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Order accepting SIL Values for the Northeast Region (ER14-225 et al.)**

On June 6, 2014, the FERC accepted the following Simultaneous Transmission Import Limit ("SIL") values that will be used by the FERC to analyze updated market power analyses submitted for the New England region:[84]

Study Area	Winter 2011	Spring 2011	Summer 2012	Fall 2012
ISO-NE	4,548	4,548	4,548	4,548
CT Import Interface	2,500	2,500	2,500	2,500
SWCT Import Interface	2,450	2,900	3,200	2,820

The 2012 SIL for the New England-wide geographic market and the Connecticut Import Interface ("CT Import Interface") and the Southwest Connecticut Import Interface ("SWCT Import Interface") geographic submarkets, identified to assist New England sellers in preparing their updated market power indicative screens and Delivered Price Test ("DPT") analyses to be submitted pursuant to Order 697, were filed by the ISO on November 20, 2013.

[83] *See NSTAR Elec. Co.*, 123 FERC ¶ 61,270 at P 5 (2008).

[84] *New Brunswick Energy Mkt'g Corp. et al.*, 147 FERC ¶ 61,190 (June 6, 2014). SIL studies are used as a basis for calculating import capability to serve load in the relevant geographic market when performing market power analyses. SIL values quantify a study area's simultaneous import capability from its aggregated first-tier area. The values accepted were based on SIL studies, or alternatively, simultaneous Total Transfer Capability ("TTC") or other data in the case of the CT and SWCT submarkets. The June 6 Order also accepted SIL values for New Brunswick, NYISO, New York City, Long Island, PJM, PJM East, AP South, and 5004/5005.

- **Day-Ahead Energy Market and Reserve Adequacy Analysis Timing Report (ER13-895)**

In its April 24, 2013 order accepting NEPOOL's proposal to have the Day-Ahead Energy Market ("DAM") bidding window close at 10:00 a.m., as opposed to the 9:00 a.m. deadline proposed by the ISO,[85] the FERC directed ISO-NE to submit "an informational report detailing the impact of the schedule changes on system operations, within one (1) year of the effective date of the Tariff revisions accepted here."[86] The ISO filed on May 23, 2014, its report containing its analysis of the impact of the schedule changes on system operations beginning with May 23, 2013 when revisions to the DAM and RAA schedules went into effect. The report, which was shared with stakeholders on April 23, 2014, and reflects Participant feedback received, finds that the DAM and RAA timing changes have incrementally improved gas-electric coordination. Specifically, the report finds the following:

(1) Preliminary evidence suggests that the schedule changes have had a positive impact on system operations, as the number of units committed in the DAM or RAA who were completely unavailable in real time due to gas procurement issues (excluding units that had their schedules extended due to reliability or capacity issues) dropped from seven in the winter of 2012/20134 to zero in the winter of 2013/2014.
(2) The number of generators with long start-up times dispatched before the DAM offer and bid deadline dropped from 12 in the winter of 2012/2013 to zero in the winter of 2013/2014, which may be attributed at least in part to the timing changes.
(3) The timing changes have had no discernible effect on the timing or volume of gas traded on the Algonquin pipeline (based on Intercontinental Exchange data).
(4) The number of external transactions has not decreased, as some argued it would.
(5) The new, shorter, Re-Offer Period appears to be functioning adequately.
(6) The timing changes appear to improve the ISO's ability to make commitments through the DAM and RAA process, which has a positive impact on electric market efficiency. In addition, the ISO has already observed an improvement in the overall DAM clearing time from enhanced hardware and business processes.

The ISO reported that it will continue to evaluate further improvements to the DAM clearing time by enhancing the underlying architecture to utilize parallel computing techniques and speed up the security analysis component and data transfer. The ISO further noted that, despite the incremental improvements, the timing differences between the gas market and the electric market continue to cause significant inefficiencies in the electric market and the ISO expects to continue its efforts to improve gas-electric coordination by participating fully in the FERC's NOPR proceedings in RM14-2 discussed below. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013 IMM Annual Markets Report (ZZ14-4)**

As previously reported, the ISO's IMM filed its 2013 Annual Markets Report on May 6, 2014, which covered the period from January 1, 2013 to December 31, 2013.[87] The report addressed the development, operation, and performance of the New England Markets in 2013 and presented an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 12.3 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for several years in a row, that the New England Market operated

[85] *ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (2013) ("*DAM Timing Jump Ball Order*"). The rest of the process timing shifts by one hour as well, in order to provide gas-fired generators the ability to submit informed bids in the DAM based on the most liquid trading portions of the day for providing gas

[86] Id. at P 37. The report must include supporting data regarding the impact of the schedule changes on system operations, the amount of long-lead-time generation dispatched outside of the RAA process, the effects on the gas market, and an assessment of the new re-offer period and any impacts on electric market efficiency.

[87] Please note that the filings of Annual Markets Reports are not noticed for public comment by the FERC.

competitively in 2013, with market concentration low, and energy prices at levels consistent with the short-run marginal cost of production. Overall, the IMM concluded, market outcomes reflected the increase in natural gas prices compared with 2012, causing energy costs in 2013 to be higher than in 2012. Other highlights included:

- Total costs increased 45%, while energy costs increased 57%. The increase in energy costs was the result of an increase in natural gas prices. Higher ancillary service costs resulted from increased reserves purchases in the Forward Reserve Market ("FRM") and system-wide 30-minute reserve requirements, as well as the inclusion of opportunity costs in the calculation of the regulation clearing price.
- The IMM has supplemented the factors that it uses to evaluate whether or not resources have met their capacity supply obligations since that list was first published in September 2013.
- In 2013, the number of hours with positive prices for 30-minute operating reserves (TMORs) increased by 40%, or an additional 28 hours compared with 2012. The IMM identified as factors explaining the increase (i) the addition of "replacement reserves" to the TMOR requirement, beginning in October 2013, that increased the requirement by 20 to 25%, and (ii) several days of tight system conditions in July, September, October, and December 2013.

In light of its review, the IMM made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2014. These recommendations will be discussed in more detail at the Participants Committee June Summer Meeting (Agenda Item #7).

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)**

The ISO filed its twenty-third report on June 19, 2014. As previously reported, the ISO committed in the August 5, 2008 Regulation Filing to provide the FERC with quarterly reports on its progress in implementing and carrying out market rule revisions to allow non-generating resources to provide Regulation, including the Alternative Technologies Pilot Program.[88] In the 23rd report, the ISO reported that, given the FERC's May 20 Order rejecting proposed changes to the Regulation Market (ER14-1537) and efforts "to complete the implementation of projects that are of far greater significance to the reliable and efficient operation of the New England markets than the regulation market" (the most significant of which is the Offer Flexibility Changes project), it will not be able to implement the new regulation market on October 1, 2014. The ISO reported that it is working to develop a plan for implementing the new regulation market after October 1, 2014, which it plans to discuss with stakeholders. "In any event, the ISO expects to submit a filing by the end of July 2014 to defer the effective date for the new regulation market until sometime after the December 2014 implementation of the Offer Flexibility Changes project and to explain the status of the ISO's effort to identify a proposed solution to the concerns discussed in the May 20, 2014 Order." These reports are not noticed for public comment.

- **ISO-NE FERC Form 714 (not docketed)**

On May 30, the ISO submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2013. Through its Form 714 filing, the ISO reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric

[88] *See* Market Rule 1 revisions regarding the provision of Regulation by non-generating resources, *ISO New England Inc. and New England Power Pool*, Docket Nos. ER08-54-000 and -001 (filed Aug. 5, 2008) (the "Regulation Filing").

utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for comment.

- **ISO-NE FERC Form 3Q (not docketed)**

On May 30, the ISO submitted its 2014/Q1 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **June 2014 Membership Filing (ER14-2089)**

On May 30, NEPOOL requested that the FERC accept: (i) the termination of the Participant status of 511 Plaza, 511 Plaza Energy, Black Bear HVGW, Black Bear SO, Topsham Hydro Partners, Capital Power, and FirstLight Power Resources Management (each effective May 1, 2014 except for FirstLight which is to become effective June 1, 2014); and (ii) the name change of Direct Energy Business Marketing (f/k/a Hess Energy Marketing).

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; *pmgerity@daypitney.com*).

- **FFT Report: May 2014 (NP14-43)**

NERC submitted on May 30, 2014, its Find, Fix, Track and Report ("FFT") informational filing for the month of May 2014. The February FFT resolves 6 possible violations of 5 Reliability Standards that posed a risk minimal risk to bulk power system ("BPS") reliability, but which have since been remediated.[89] The 4 Registered Entities involved each submitted a mitigation activities statement of completion. These filings are for information only and will not be noticed for public comment by the FERC.

- **Revised Reliability Standards: VAR-001-4 and VAR-002-3 (RD14-11)**

On June 9, 2014, NERC filed for approval changes to VAR-001-4 (Voltage and Reactive Control) and VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) ("VAR Changes"). NERC states that the VAR Changes are designed to address outstanding directives from *Order Nos. 693*[90] and *724*[91] and build upon the previous versions of the Reliability Standards to improve their quality and content. NERC requested that the VAR Changes be approved, and the existing VAR-001-3 and VAR-002-2b be retired, effective on the first day of the first calendar quarter after FERC approval. Comments on the VAR Changes are due on or before July 14, 2014.

- **Revised Reliability Standard: PER-005-2 (RD14-7)**

On June 19, the FERC approved PER-005-2 (Operations Personnel Training) ("PER-005 Changes"), including NERC's proposed implementation plan, the retirement of PER-005-1, the proposed VRF and VSLs, and

[89] Only possible violations that pose a minimal risk to Bulk-Power System reliability are eligible for FFT treatment. *See N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (Mar. 15, 2012) at PP 46-56.

[90] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) ("*Order 693*").

[91] *Elec. Re. Org. Interpretations of Specific Reqs. of Frequency Response and Bias and Voltage and Reactive Control Rel. Standards*, Order No. 724, 127 FERC ¶ 61,158 (2009) ("*Order 724*").

the addition of "Operations Support Personnel" and changes to "System Operator" in NERC's Glossary of Terms.[92] The PER-005 Changes are designed to expand training requirements to include local transmission control center operator personnel, Operations Support Personnel and the applicable Generator Operator dispatch personnel. The PER-005 Changes were approved effective July 1, 2016. The lengthy implementation period reflects the applicability of the revised Standard to functional entities (Transmission Owners and Generator Operators) not currently subject to PER-005-1, who will for the first time be required to develop and implement a systematic approach to training process for their applicable personnel. Any challenges to the *PER-005 Changes Order* will be due on or before July 21.

- **Revised Reliability Standards: MOD-032-1, MOD-033-1 (RD14-5)**

On May 1, 2014, the FERC approved changes to two Modeling, Data, and Analysis Standards, MOD-032-1 (Data for Power System Modeling and Analysis) and MOD-033-1 (Steady-State and Dynamic System Model Validation), to replace, consolidate and improve upon the "Existing MOD B Standards[93]" in addressing system-level modeling data and validation requirements ("MOD Revisions"). Changes to the Revised Standards will become effective on the first day of the first calendar quarter that is one year (in the case of MOD-032 R1), two years (in the case of MOD-032 R2, R3, R4), and three years (in the case of MOD-033) after the May 1 approval date. The May 1 letter order was not challenged and is final and unappealable.

On May 7, 2014, the FERC issued a notice and request for comments (by July 14, 2014)[94] on (a) whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

- **Revised Reliability Standards: INT-004-3, INT-006-4, INT-009-2, INT-010-2, INT-011-1 (RD14-4)**

On February 27, 2014, NERC filed for approval changes to the following five Interchange and Coordination Standards ("INT Changes"):

- INT-004-3 – Dynamic Transfers;
- INT-006-4 – Evaluation of Interchange Transactions;
- INT-009-2 – Implementation of Interchange;
- INT-010-2 – Interchange Initiation and Modification for Reliability; and
- INT-011-1 – Intra-Balancing Authority Transaction Identification.

The INT Changes are designed to consolidate nine currently effective INT Standards into five new Standards[95] that clarify responsibility for Interchange Authority tasks. In addition, NERC requested approval of associated VRFs and VSLs, a proposed implementation plan, and four new and ten revised definitions[96] for inclusion in its

[92] *N. Amer. Elec. Rel. Corp.*, 147 FERC ¶ 61,226 (June 19, 2014) ("*PER-005 Changes Order*").

[93] Just two of The Existing MOD B Standards, MOD-010-0 and MOD-12-0 were approved in *Order 693*. The other four Existing MOD B Standards were deemed "fill-in-the-blank" standards and were neither approved nor remanded but remain pending. *Order 693* at PP 1131-1222. The February 25 filing requests approval to retire MOD-010-0 and MOD-012-0 and withdraw MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1.

[94] The request for comments was published in the *Fed. Reg.* on May 14, 2014 (Vol. 79, No. 93) pp. 27,588-89.

[95] The 5 existing INT Standards to be replaced by INT-011-1 are: INT-001-3 (Interchange Information); INT-003-3 (Interchange Transaction Implementation); INT-005-3 (Interchange Authority Distributes Arranged Interchange); INT-007-1(Interchange Confirmation); and INT-008-3 (Interchange Authority Distributes Status).

[96] The proposed new Definitions are: Attaining Balancing Authority; Native Balancing Authority; Composite Confirmed Interchange; and Reliability Adjustment Arranged Interchange; proposed revised Definitions are: Adjacent

Glossary of Terms ("Definitions"). NERC requested that the revised INT Standards, VRFs, VSLs, Implementation Plan, and Definitions be approved effective on the first day of the second calendar quarter that is after the date that the proposed INT Standards are approved by the FERC. Comments on the revised Reliability Standards were due on or before March 31, 2014; no comments were filed. Interventions were filed by EEI and EPSA.

On June 18, 2014, the FERC issued a notice and request for comments (by August [60 days after its publication in the *Federal Register*], 2014)[97] on (a) whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

This matter is pending before the FERC.

- **New Reliability Standard: CIP-014-1 (Physical Security) (RM14-15)**

In response to the FERC's March 7 order directing NERC to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the BPS,[98] NERC, on May 23, 2014, filed for approval one new Reliability Standard – CIP-014-1 (Physical Security). Proposed CIP-014 is to enhance physical security measures for the most critical Bulk-Power System facilities and thereby lessen the overall vulnerability of the Bulk-Power System to physical attacks. CIP-014 requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or cascading within an Interconnection. CIP-014 also includes requirements for: (i) the protection of sensitive or confidential information from public disclosure; (ii) third party verification of the identification of critical facilities as well as third party review of the evaluation of threats and vulnerabilities and the security plans; and (iii) the periodic reevaluation and revision of the identification of critical facilities, the evaluation of threats and vulnerabilities, and the security plans to help ensure their continued effectiveness. NERC requested that CIP-014 become effective as of the first day of the first calendar quarter that is 6 months after the date that CIP-014 is approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

- **Revised Reliability Standard: COM-001-2 and COM-002-4 (RM14-13)**

On May 14, 2014, NERC filed for approval changes to COM-1 (Communications) and COM-2 (Operating Personnel Communications Protocols) (together, "COM Changes"). Proposed COM-001 establishes a clear set of requirements for what communications capabilities various functional entities must maintain for reliable communications. Proposed COM-002 improves communications surrounding operating instructions by setting predefined communications protocols, requiring use of the same protocols regardless of the current operating condition (whether normal, alert, and Emergency operating conditions), and requiring entities to reinforce the use of the documented communication protocols through training, assessment, and feedback. NERC requested that the COM Changes be approved effective as of the first day of the first calendar quarter that is 12 months after the date that the COM Changes are approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

Balancing Authority; Arranged Interchange; Confirmed Interchange; Dynamic Interchange Schedule or Dynamic Schedule; Intermediate Balancing Authority; Operational Planning Analysis; Pseudo-Tie; Request for Interchange; Sink Balancing Authority; and Source Balancing Authority.

[97] The request for comments has, as of the date of this Report, not yet been published in the *Fed. Reg.*

[98] *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (Mar. 7, 2014).

- **Revised Reliability Standard: MOD-031-1 (RM14-12)**

On May 13, 2014, NERC filed for approval changes to MOD-31 (Demand and Energy Data) ("MOD-031 Changes"). The MOD-031 Changes are designed to replace, consolidate and improve upon the "existing MOD-C Standards"[99] in addressing the collection and aggregation of Demand and energy data necessary to support reliability assessments performed by the ERO and Bulk-Power System planners and operators. Specifically, the MOD-031 Changes, in response to *Order 693*, (1) streamline the MOD Reliability Standards to clarify data collection requirements; (2) include Transmission Planners as applicable entities that must report Demand and energy data; (3) require applicable entities to report weather-normalized annual peak hour actual Demand data from the previous year to allow for meaningful comparison with forecasted values; and (4) require applicable entities to provide an explanation of, among other things: (i) how their Demand Side Management forecasts compare to actual Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.; and (ii) how their peak Demand forecasts compare to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted. Consistent with FERC's directives, NERC is also proposing to revise the definition of Demand-Side Management to include activities or programs undertaken by any applicable entity, not just a Load Serving Entity or its customers, to achieve a reduction in Demand. NERC requested that the MOD-031 Changes be approved, and the existing MOD-C Standards be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the MOD-031 Changes are approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

- **Revised Reliability Standard: BAL-001-2 (RM14-10)**

On May 9, 2014, NERC filed for approval changes to BAL-001-2 (Real Power Balancing Control Performance) ("BAL-001 Changes"). The BAL-001 Changes add a frequency component to the measurement of a Balancing Authority's Area Control Error ("ACE") and allows for the formation of "Regulation Reserve Sharing Groups." NERC requested that the BAL-001 Changes be approved, and the existing BAL-001-1 Standard be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the BAL-001 Changes are approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

- **Revised Reliability Standard: PRC-005-3 (RM14-8)**

On February 14, 2014, NERC filed for approval changes to PRC-005-3 (Protection System and Automatic Reclosing Maintenance) ("PRC-005 Changes"). The PRC-005 Changes are designed to include in PRC-005 the maintenance and testing of reclosing relays that can affect the reliable operation of the BPS. NERC requested that the PRC-005 Changes be approved, and the existing PRC-005-2 be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the PRC-005 Changes are approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

- **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

On June 19, 2014, the FERC issued a NOPR proposing to approve changes to MOD-001-2 (Modeling, Data, and Analysis — Available Transmission System Capability) ("MOD Changes") proposed by NERC. The MOD Changes replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC"). MOD-001-2 will replace the six Existing MOD Standards[100] to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that

[99] The "existing Mod-C Standards" are: MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1.

[100] The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2's effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC seeks comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also seeks further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR are due [60 days from the date of publication in the *Federal Register*].[101]

- **NOPR: Revised Reliability Standards: PRC-023-003 and -025-001 (RM14-3; RM13-19)**

On March 20, 2014, the FERC issued a NOPR proposing to approve changes to PRC-023 (Transmission Relay Loadability) and changes to PRC-025 (Generator Relay Loadability) filed by NERC in Docket Nos. RM14-3 and RM13-19.[102] PRC-025-1 was proposed in response to FERC directives in Order 733[103] to address generator protective relay loadability. PRC-023-003 was developed to establish a bright-line between the applicability of load-responsive protective relays in the transmission and generator relay loadability Reliability Standards. NERC requested that the revised PRC Standards become effective in accordance with the implementation plans filed with the revised Standards, or the first day of the first calendar quarter following FERC approval of the revised Standards. Comments on the NOPR were due on or before April 28, 2014,[104] and were filed by NERC, EEI/EPSA, and by three individuals. This matter is pending before the FERC.

- ***Order 797*: New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations) (RM14-1)**

On June 19, 2014 the FERC approved new Reliability Standard EOP-010-1 (Geomagnetic Disturbance Operations).[105] The new Reliability Standard requires Bulk-Power System owners and operators to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances consistent with the reliable operation of the BPS. The FERC also approved the associated VRFs and VSLS, implementation plan, and effective dates proposed by NERC. Accordingly, EOP-010-1 will become effective January 1, 2015. Challenges, if any, to *Order 797* are due on or before July 21, 2014.

- **NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)**

On November 21, 2013, the FERC issued a NOPR[106] proposing (i) to approve NERC's proposed revisions to Reliability Standard TOP-006-3 (Monitoring System Conditions) filed in RM13-12, but (ii) to remand changes to the following Interconnection Reliability Operations and Coordination ("IRO") and Transmission Operating ("TOP") Reliability Standards filed in RM13-14 and RM13-15:

- IRO-001-3 (Reliability Coordination — Responsibilities and Authorities);
- IRO-002-3 (Reliability Coordination – Analysis Tools);
- IRO-005-4 (Reliability Coordination – Current Day Operations);

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[101] The MOD-001-2 NOPR has, as of the date of this Report, not yet been published in the *Fed. Reg.*

[102] *Generator Relay Loadability and Revised Transmission Relay Loadability Reliability Standards*, 146 FERC ¶ 61,189 (Mar. 20, 2014) ("*Loadability NOPR*").

[103] *Transmission Relay Loadability Standard*, Order No. 733, 130 FERC ¶ 61,221, at P 104-08 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127, *order on reh'g and clarification*, Order No. 733-B, 136 FERC ¶ 61,185 (2011).

[104] The Loadability NOPR was published in the *Fed. Reg.* on Mar. 27, 2014 (Vol. 79, No. 59) pp. 17,077-17,082.

[105] *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 147 FERC ¶ 61,209 (June 19, 2014) ("*Order 797*").

[106] *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (Nov. 21, 2013) ("*Nov 21 NOPR*").

- IRO-0014-2 (Coordination Among Reliability Coordinators);
- TOP-001-2 (Transmission Operations);
- TOP-002-3 (Operations Planning);
- TOP-003-2 (Operational Reliability Data); and
- PRC-001-2 (System Protection Coordination).[107]

As previously reported, the changes to TOP-006-3 filed April 5, 2013 are targeted to address the respective monitoring role and notification obligation of Reliability Coordinators ("RCs"), Balancing Authorities ("BAs") and Transmission Operators ("TOPs") by clarifying that TOPs are responsible for monitoring and reporting available transmission resources and that BAs are responsible for monitoring and reporting available generation resources. In addition, the changes confirm that RCs, TOPs, and BAs are required to supply their operating personnel with appropriate technical information concerning protective relays located within their respective areas.

The changes to the IRO Standards were to achieve two important overall reliability benefits: (1) delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) improve system performance by raising the bar on monitoring of Interconnection Reliability Operating Limits ("IROLs") and System Operating Limits ("SOLs") in order to focus monitoring on IROLs and SOLs that are important to reliability.

The changes to the remaining TOP Standards were to upgrade the overall quality of the Standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address *Order 693* directives. NERC indicated in its April filing that the proposed TOP Standards are also more efficient than the currently-enforceable TOP Reliability Standards because they incorporate the necessary requirements from the eight currently-effective TOP Reliability Standards (TOP-001-1a, TOP-002-2.1b, TOP-003-1, TOP-004-2, TOP-005-2a, TOP-006-2, TOP-007-0, TOP-008-1) and the PER-001-0.2 Reliability Standard into three cohesive, comprehensive Reliability Standards that are focused on achieving a specific result.

Because the proposed TOP and IRO Reliability Standards were interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involved similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the FERC addressed all three proposals together in the one NOPR. Although the FERC acknowledged that the proposed TOP and IRO Reliability Standards contain some improvements over the current Standards, concerns that the changes would create reliability gaps in the Standards that are critical to reliable operation of the BPS resulted in the proposed remand of the proposed TOP Standards.[108] The FERC went on to explain that

> given the interrelationship between the TOP and IRO Reliability Standards and that NERC requests that both sets of standards be addressed together, we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.[109]

[107] The changes in proposed PRC-001-2 were administrative in nature and were limited to removal of three requirements in currently-effective PRC-001-1 that were to be addressed in proposed TOP-003-2.

[108] *Id.* at P 4.

[109] *Id.*

Initially, comments are the *Nov 21 NOPR* were due on or before February 3, 2014.[110] However, on December 20, NERC requested that the FERC defer action in this proceeding to January 31, 2015 to allow NERC time to consider the reliability concerns raised by the FERC in the *Nov 21 NOPR* and by an independent review commissioned by NERC that identified proposed TOP-001-2, PRC-001-2, IRO-001-3, and IRO-005-4 as high risk standards requiring improvement. On January 6, 2014, the ISO/RTO Council and NRECA filed comments supporting NERC's requested deferral. On January 14, 2014, the FERC granted NERC's motion to defer action on the *Nov 21 NOPR* until January 31, 2015, including deferral of the comment due date. Comments were nonetheless submitted on February 3, 2014 by BPA and Idaho Power. On April 1, 2014, NERC submitted the first of its promised quarterly status reports regarding the status of revisions. In the report, NERC noted that two technical conferences were held by NERC in March, and the Standard Drafting team would meet at least twice in April to work on revisions to the Standards.

- **Revised VSL: PRC-005 R1 (RM13-7)**

On June 4, 2014, NERC requested that the FERC approve a revised VSL for PRC-005 reflecting that the VSL level for failure to include station batteries in a time-based maintenance program would be "severe." As of the date of this report, a comment date has not been set for this filing.

- **NOPR: BAL-002-1a Interpretation Remand (RM13-6)**

This May 16, 2013 NOPR, which proposes to remand NERC's proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.[111] NERC asserted that the proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard. Specifically, the proposed interpretation would clarify that: (1) a Disturbance that exceeds the most severe single Contingency, regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency. The FERC, however, proposes to remand the proposed interpretation because it believes the interpretation changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations. Comments on the *BAL-002-1a Interpretation Remand NOPR* were due on or before July 8, 2013,[112] and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR remains pending before the FERC.

- ***Order 791-A*: Version 5 CIP Reliability Standards (-002 through -011) (RM13-5)**

On November 22, 2013, the FERC approved the Version 5 Critical Infrastructure Protection ("CIP") Reliability Standards submitted by NERC, which adopt new cyber security controls and extend the scope of the systems that are protected by the CIP Standards.[113] The FERC also approved 19 new or revised definitions associated with the CIP version 5 Standards for inclusion in NERC's Glossary of Terms. In addition, as it proposed in the prior NOPR, the Commission directed NERC to develop modifications to the CIP version 5 Standards to address concerns that limited aspects of the CIP Version 5 Standards are potentially ambiguous and may raise questions regarding the enforceability of the standards. The FERC also directed NERC to submit

[110] The *Nov 21 NOPR* was published in the *Fed. Reg.* on Dec. 5, 2013 (Vol. 78, No. 234) pp. 73,112-73,128.

[111] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[112] The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

[113] *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (Nov. 22, 2013) ("*Order 791*"), *clarification granted in part and reh'g denied*, 146 FERC ¶ 61,188 (Mar. 20, 2014).

informational filings regarding certain issues during and following implementation of the CIP version 5 Standards. *Order 791* became effective February 3, 2014.[114]

Technical Conference. On April 29, 2014, the FERC held a staff-led technical conference on CIP issues identified in *Order 791*. Technical Conference panelists were asked to address: (1) whether additional definitions and/or security controls are needed to protect Bulk-Power System communications networks, including remote systems access; (2) the adequacy of the approved CIP version 5 Standards' protections for Bulk-Power System data being transmitted over data networks; and (3) functional differences between the respective methods utilized for identification, categorization, and specification of appropriate levels of protection for cyber assets using CIP version 5 Standards as compared with those employed within the National Institute of Standards and Technology Security Risk Management Framework. Post-technical conference comments on the matters discussed were filed on May 21, 2014 by EEI, SoCal Edison, SRC Cyber, and 2 individuals.

Revisions to VRFs and VSLs. On May 15, NERC filed, in accordance with *Order 791*, proposed revisions to the following VRFs and VSLs assigned to certain CIP Standards:

- VRF assigned to CIP-006-5, Requirement R3
- VRF assigned to CIP-004-5.1, Requirement R4
- VSL assigned to CIP-003-5, Requirements R1 and R2
- VSL assigned to CIP-004-5.1, Requirement R4
- VSL assigned to CIP-008-5, Requirement R2
- VSL assigned to CIP-009-5, Requirement R3

Comments on the Revised VRFs and VSLs were due on or before June 5, 2014; none were filed. The revised VRFs and VSLs are pending before the FERC.

- **Market Implications of Frequency Response and Frequency Bias Setting Requirements (AD13-8)**

On July 18, 2013, the FERC solicited comment on the potential market and commercial impacts of certain of the requirements of BAL-003-1 (Frequency Response and Frequency Bias Setting).[115] The FERC did not propose changes to proposed Reliability Standard BAL-003-1. Rather, the FERC indicated the comments would inform its consideration and coordination of the requirements of the proposed Standard with tariffs and markets rules subject to its jurisdiction.[116] Comments were due on October 18, 2013. Comments were submitted by NERC, Arizona Public Service, BPA, EEI, EPSA, the Electricity Consumers Resource Council, the Electricity Storage Association ("ESA"), MISO and PJM, and PG&E. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **FirstEnergy PJM DR Complaint (EL14-55)**

On May 23, 2014, the same day that DC Circuit vacated *Order 745* (*see* Section XV below), FirstEnergy filed a complaint against PJM requesting that the FERC require the "removal of all portions of the PJM Tariff allowing or requiring PJM to include demand response as suppliers to PJM's capacity markets". FirstEnergy also requested that the results of the PJM capacity auction due to be released that same day, to the extent it included and cleared demand response resources, be considered void and legally invalid.

[114] *Order 791* was published in the *Fed. Reg.* on Dec. 3, 2013 (Vol. 78, No. 232) pp. 72,756-72, 787. As previously reported, and as requested, the FERC granted an extension of the compliance deadline for the Version 4 CIP Reliability Standards from Apr. 1, 2014 to Oct. 1, 2014. *See Version 4 Critical Infrastructure Protection Reliability Standards and Version 5 Critical Infrastructure Protection Reliability Standards*, 144 FERC ¶ 61,123 (2013).

[115] *Market Implications of Frequency Response and Frequency Bias Setting Reqs.*, 144 FERC ¶ 61,058 (July 18, 2013).

[116] *Id.* at P 2.

PJM's response, and all comments and interventions were initially due on or before June 12, 2014. However, on June 11, the FERC extended that date to 30 days after the submission by FirstEnergy of an amended complaint (which as of the date of this Report, has not yet occurred). Thus far, nearly 50 parties have moved to intervene; no comments or responses have yet been filed. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)**

On December 18, 2012, Judge Sterner issued his 374-page initial decision which, following hearings described in previous reports, found at its core that "it is unjust, unreasonable, and unduly discriminatory to allocate costs of Phase Angle Regulating Transformers ("PARs") of the International Transmission Company ("ITC") to NYISO and PJM",[117] which the Midwest ISO ("MISO") and ITC proposed unilaterally to do (without the support of either PJM or NYISO) in its October 20, 2010 filing initiating this proceeding. For a summary of specific findings, please refer to any of the January to June 2013 Reports.

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. Briefs opposing exceptions were filed by the FERC Trial Staff, MISO TOs, NYISO, NY TOs, PJM, and the PJM TOs. On February 25, Joint Applicants moved to strike a portion of the PJM Brief Opposing Exceptions. On March 12, PJM answered Joint Applicants February 25 motion. Since the last report, MISO (now called "Midcontinent Independent System Operator, Inc.") moved to lodge a NYISO "Broader Regional Markets Informational Report" filed March 19, 2014 in ER08-1281 and a related January 16, 2014 "Ontario-Michigan Interface PAR Performance Evaluation Report" ("Evaluation Report") prepared by MISO, IESO and PJM. Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, and PSEG. This matter remains pending before the FERC. If there are any questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Generator. On April 1, 2014, the FERC issued a notice that Staff has preliminarily determined that Indianapolis Power & Light Company ("IPL") violated section 39.2.5 (c) of the MISO Tariff by failing to update the real-time offer for its Petersburg 2 generating unit to reflect a de-rate of that unit on July 5 and 6, 2012.

Marketer. On June 12, 2014, the FERC issued a notice that Staff has preliminarily determined that Twin Cities Power-Canada, U.L.C. and certain affiliated companies, including Twin Cities Energy and Twin Cities Power, and individuals Allan Cho, Jason F. Vaccaro, and Gaurav Sharma each violated the FERC's prohibition of electric energy market manipulation by scheduling and trading physical power in MISO to benefit related swap positions that settle off of real-time MISO prices, including the Cinergy Hub Balance-of-Day Swap traded on IntercontinentalExchange, Inc. ("ICE"), during the period January 1, 2010 through January 31, 2011.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[118] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **Waiver of Transmission Standards of Conduct: Emera Maine (f/k/a Bangor Hydro) Request (TS11-5)**

Emera Maine's October 31, 2011 amended waiver request remains pending before the FERC. As previously reported, the FERC denied, without prejudice, Bangor Hydro's initial request for waiver of the

[117] *Midwest Indep. Trans. Sys.Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) ("*MISO Initial Decision*") at P 923.

[118] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

FERC's Standards of Conduct requirements.[119] Bangor Hydro requested a limited waiver from the FERC's Standards of Conduct requirements,[120] to the extent necessary, to permit its transmission function personnel to undertake the actions necessary to re-sell into the New England Market energy from the Rollins Project which the MPUC has mandated it purchase but cannot otherwise sell at retail. The FERC stated that it would revisit its determination if Bangor Hydro brought forward information demonstrating that it met the criteria for waiver set forth in section 358.1(c) and summarized in the order (i.e. a demonstration that Bangor Hydro has no access to information concerning the operation of the transmission facilities by the ISO and that it obtains information about such matters only by viewing the ISO's OASIS). In response to the *BHE Standards of Conduct Order*, Bangor Hydro amended its waiver request in 2 respects: First, Bangor Hydro revised its request to apply only to the energy required to be purchased from the Rollins Project and the Exeter Agri-Energy Project. Second, Bangor Hydro committed, as a condition of the waiver (if granted), not to engage in any purchases or sales of wholesale electric capacity or energy except for those required under Maine laws and/or regulations or orders of the MPUC. The MPUC filed comments supporting Bangor Hydro's amended waiver request on November 15, 2011. This matter remains pending before the FERC.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Reliability Technical Conference (AD14-9)**

On June 10, 2014, the FERC held a Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System. Four panel discussions addressed issues raised by the following topics: (1) 2014 State of Reliability Report and Emerging Challenges; (2) Emerging Issues; (3) ERO Initiatives; and (4) ERO Performance. Speaker materials are posted in eLibrary. For those that may have missed the conference, a free recording of the conference is available at http://ferc.capitolconnection.org/061014/fercarchive_wmv.htm. Written comments regarding the matters discussed at the technical conference will be accepted through July 15, 2014.

- **Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)**

On June 19, 2014, the FERC initiated a proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets. In its notice, the FERC announced a series of staff workshops to facilitate a discussion with market operators and their stakeholders on the existing market rules and operational practices related to:

  - use of uplift payments;
  - offer price mitigation and offer price caps;
  - scarcity and shortage pricing; and
  - operator actions that affect price.

The first workshop, which staff plans to hold by early September, will explore uplift in detail, while also providing an opportunity to begin a discussion on the scope of remaining topics. Additional workshops on the other price formation topics will be announced in the coming months. The FERC has established a web page for this issue at http://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp.

- **RTO/ISO Winter 2013-2014 Op and Market Performance (AD14-8)**

On April 1, 2014, the FERC held a technical conference to explore the impacts of and actions taken to respond to recent cold weather events by RTO/ISOs. Discussion focused on: the impact of cold weather events on operational planning and real-time operations, market prices and performance, and regional infrastructure; the actions taken in response to those impacts; gas procurement; and lessons learned that can be

[119] *Bangor Hydro-Elec. Co.*, 136 FERC ¶ 61,182 (Sep. 15, 2011) ("*BHE Standards of Conduct Order*").

[120] *See* 18 C.F.R. § 358 (2013) *et seq.*

shared between regions and applied in future events. ISO-NE's materials were circulated to the Committee on April 1, and are posted with the composite materials for the April 4 meeting. Speaker materials are posted in the FERC's eLibrary as well as at: http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7272&CalType=&CalendarID=116&Date=&View=Listview. For those that may have missed the conference, a free recording of the conference will be archived at http://ferc.capitolconnection.org/ for at least three months. Post-conference comments were filed by over 40 parties, including: ISO-NE, APPA, Dominion, EEI, Entergy, EPSA, Essential Power, Exelon, Macquarie, MMWEC/CMEEC, PSEG, Vitol.

- **Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services (AD14-7)**

As previously reported, the FERC held a workshop, on April 22, 2014, to obtain input on third-party provision of reactive supply and voltage control and regulation and frequency response services. Discussion focused on: whether reactive supply and frequency response should be considered obligations without payment or services provided for payment, and on market power screening concerns associated with reactive supply, regulation, and frequency response services. Also on April 22, FERC Staff issued a "Report re Payment for Reactive Power". Since the last Report, post-workshop comments were submitted by APS, AWEA, Bonneville, EPSA, ESA, Grid Storage, MISO, PG&E, Powerex, SmartSenseCom, and a transcript of the workshop was posted on eLibrary.

- **Zero Rate Reactive Power Rate Schedules (AD14-1)**

On December 11, 2013, FERC staff led a workshop that explored the mechanics of filing reactive power rate schedules for which there is no compensation. The workshop was held pursuant to a FERC directive in *Chehalis.*[121] Interested persons were invited to file written comments, on or before January 24, 2014, focused on the mechanics of filing reactive power rate schedules for which there is no compensation. Seven sets of comments were filed, including comments by AMP, AWEA/EEI, DTE, EPSA, and NRG.

- **RTO/ISO Centralized Capacity Markets (AD13-7)**

On September 25, 2013, the FERC held a technical conference on centralized capacity markets. The purpose of the technical conference was to consider how current capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The technical conference provided an opportunity to review the market rules and structures at a high level and examine how they are accomplishing their intended goals and objectives. The technical conference focused on the goals and objectives of existing centralized capacity markets (e.g., resource adequacy, long-term price signals, fixed-cost recovery, etc.) and examined how specific design elements are accomplishing existing and emerging goals and objectives. Comments and presentations have been posted in eLibrary under Docket No. ER13-7. On October 25, the FERC issued a notice inviting post-tech conference comments on any or all of questions attached to the Notice regarding capacity markets in the three Northeast Control Areas. Comments were due on or before January 8, 2014 and were filed by over 50 parties, including the following New England parties: Brookfield, CMEEC, CPV, EMCOS, Entergy, Exelon, GDF SUEZ, Green Mountain Power, LIPA, MMWEC, NEPGA, Potomac Economics, PSEG, UCS, Viridity, Vitol, VT DPS, and an *ad hoc* group of "load" parties.[122]

- **NOPR: MBR Authorization Refinements (RM14-14)**

On June 19, the FERC issued a NOPR proposing to revise its current standards, and to streamline certain aspects of its filing requirements, for obtaining market-based rates ("MBR") for sales of electric energy, capacity,

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[121] *See Chehalis Power Generating, L.P.*, 145 FERC ¶ 61,052 (Oct. 17, 2013) ("*Chehalis*").

[122] The "load" parties were an *ad hoc* group of publicly and cooperatively owned electric utilities, national consumer and low-income organizations, state public utility commissions, state consumer advocates, investor-owned utilities, industrial customers, and independent power producers, including, among others, APPA, CT AG, CPV, CT DEEP, CT PURA, GMP, and the Northeast Public Power Assoc.

and ancillary services.[123] In addition, the FERC clarified certain standards for obtaining and retaining MBR authority. Among other changes, the FERC proposes (i) to permit sellers in RTO/ISO markets with Commission-approved market monitoring and mitigation to include a statement that they are relying on such mitigation to address any potential horizontal market power concerns in lieu of submitting the indicative screens; (ii) to permit sellers to explain that their qualified capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the FERC's horizontal market power tests and to submit a change in status filing when there is a net increase of 100 MW or more; (iii) to relieve sellers of their obligation to file quarterly land acquisition reports and of the obligation to provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses; (iv) to require a change in status filing if there is a 100 MW increase in cumulative nameplate capacity added in any relevant geographic market; and (v) require corporate org charts with all MBR applications and notices of change in status. Comments on this NOPR are due [60 days after publication in the *Federal Register*].

- **NOPR: Open Access and Priority Rights on ICIF (RM14-11)**

On May 15, the FERC issued a NOPR proposing to waive the Open Access Transmission Tariff requirements of 18 CFR 35.28 (2013), the Open Access Same-Time Information System requirements of Part 37 of its regulations, 18 CFR 37 (2013), and the Standards of Conduct requirements of Part 358 of its regulations, 18 CFR 358 (2013), for any public utility that is subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities ("ICIF"),[124] in whole or in part, and sells electric energy from its Generating Facility. The Commission also proposes to find that requiring the filing of an OATT is not necessary to prevent unjust or unreasonable rates or unduly discriminatory behavior with respect to ICIF over which interconnection and transmission services can be ordered. The NOPR also proposes a 5-year safe harbor period during which an ICIF owner subject to the blanket waiver, who initially has excess capacity on its ICIF because it intends to serve its own or its affiliates' future phased generator additions or expansions, may establish a rebuttable presumption for priority right over third parties to use that excess capacity. Comments on this NOPR are due on or before July 29, 2014.[125]

- **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

On June 26, WIRES[126] petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide "greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure." Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project's actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. Since the last report, WIRES submitted on October 3 a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that

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[123] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servcs. by Public Utils.*, 147 FERC ¶ 61,232 (June 19, 2014).

[124] ICIF is the term used by the FERC in the NOPR to refer to "generator tie lines".

[125] The NOPR was published in the *Fed. Reg.* on May 30, 2014 (Vol. 79, No. 104) pp. 31,061-31,072.

[126] WIRES, the **W**orking group for **I**nvestment in **R**eliable and Economic **E**lectric **S**ystems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website www.wiresgroup.com.

provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

- ***Order 792*: Revisions to *Pro Forma* SGIA and SGIP (RM13-2)**

On November 22, 2013, the FERC amended its *pro forma* Small Generator Interconnection Procedures ("SGIP") and *pro forma* Small Generator Interconnection Agreement ("SGIA"), originally set forth in Order 2006, to: (1) incorporate provisions that would provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; (2) revise the 2 MW threshold for participation in the Fast Track Process included in section 2 of the pro forma SGIP; (3) revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; (4) revise the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection; (5) revise the *pro forma* SGIP and the *pro forma* SGIA to specifically include energy storage devices; and (6) clarify certain sections of the *pro forma* SGIP and the *pro forma* SGIA.[127] *Order 792* will become effective February 3, 2014.[128]

On March 20, the FERC issued Order 792-A[129] clarifying the compliance procedures in response to *Order792:*

Compliance Filing. Each Transmission Provider must file in compliance with *Order 792* the *pro forma* language included in *Order 792* **without variation**.[130] This compliance filing made pursuant to FPA Section 206 is required to be filed on or before August 4, 2014.

Variation 205 Filing. A Transmission Provider may submit an FPA section 205 filing to demonstrate that either a variation that has not been previously approved, or a previously-approved variation from the *pro forma* language that has been substantively affected by the reforms adopted in *Order 792*, meets one of the standards for variance provided for in the Final Rule, including independent entity variations, regional reliability variations, and variations that are "consistent with or superior to" the Final Rule. Such filings are also due on or before August 4, 2014.

As previously reported, the ISO and PTO AC notified the FERC that their 6-month (August 4, 2014) compliance filing will contain independent entity variations necessary to preserve previously-approved variations and accommodate specific regional needs or differences.

- ***Order 771*: Availability of e-Tag Information to FERC Staff (RM11-12)**

Rehearing of portions of *Order 771* has been requested and remains pending. As previously reported, the FERC issued *Order 771 o*n December 20, 2012.[131] *Order 771* granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags ("e-Tags") used to schedule the transmission of electric power interchange transactions in wholesale markets. *Order 771* requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags

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[127] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013) ("*Order 792*"), *order clarifying compliance procedures*, 146 FERC ¶ 61,214 (Mar. 20, 2014).

[128] *Order 792* was published in the *Fed. Reg.* on December 5, 2013 (Vol. 78, No. 234) pp. 73,240-73,354.

[129] *Small Generator Interconnection Agreements and Procedures*, Order No. 792-A, 146 FERC ¶ 61,214 (Mar. 20, 2014) ("Order 792-A").

[130] Transmission Providers must either comply with *Order 792* or demonstrate that the FERC has previously approved variations that are not affected in a substantive manner by the reforms to the *pro forma* language

[131] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771, 141 FERC ¶ 61,235 (Dec. 20, 2012) ("*Order 771*"), *order on reh'g and clarification*, 142 FERC ¶ 61,181 (2013).

covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, *Order 771* requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. *Order 771* became effective February 26, 2013.[132] In response to requests for clarification and/or rehearing of *Order 771* filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies (collectively, the "Rehearing Requests"), the FERC issued, on March 8, 2013, *Order 771-A*.[133] *Order 771-A* addressed only those issues that needed to be answered on an expedited basis to allow affected entities to comply with the requirement to ensure FERC access in a timely manner to the e-Tags covered by *Order 771*.[134] The FERC noted that it would issue an additional rehearing order, addressing the remaining issues raised on rehearing and clarification, which therefore remain pending before the FERC.

- ***Order 764-A*: Variable Energy Resources (RM10-11)**

Requests for rehearing and/or clarification of *Order 764-A* remain pending before the FERC. As previously reported, the FERC, in *Order 764-A,*[135] affirmed its basic *Order 764* determinations,[136] provided clarification, and granted EEI's request to extend the period for compliance filings. Specifically, *Order 764-A* clarified (i) that the intra-hour scheduling reform adopted in the *Order 764* applies to ***all*** transmission customers that schedule transmission service under an OATT;[137] (ii) in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges;[138] and (iii) that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.[139] Remaining requests for clarification and/or rehearing were denied. Requests for clarification and/or rehearing of *Order 764-A* were submitted on January 22, 2013 by Powerex and Iberdrola. On February 19, 2013, the FERC issued a tolling order affording it additional time to consider the Powerex and Iberdrola requests, which remain pending before the FERC. The region's *Order 764/764-A* compliance revisions were considered and supported at the August 2, 2013 meeting. Since the last report, the ISO, NEPOOL, PTO AC, CSC and SSPs jointly filed, on November 12, 2013, New England's compliance changes (*see* Section IV, ER14-375 above). If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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132 *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

133 *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (Mar. 8, 2013) ("*Order 771-A*").

134 *Order 771-A* clarified that: (1) Balancing Authorities and their Authority Services will have until 60 days after publication of this order to implement the validation requirements of *Order 771*; (2) validation of e-Tags means that the Sink Balancing Authority, through its Authority Service, must reject any e-Tags that do not correctly include the FERC in the CC field; (3) the requirement for the FERC to be included in the CC field on the e-Tags applies only to e-Tags created on or after March 15, 2013; (4) the FERC will deem all e-Tag information made available to the FERC pursuant to *Order 771* as being submitted pursuant to a request for privileged and confidential treatment under 18 CFR 388.112; (5) the FERC is to be afforded access to the Intra-Balancing Authority e-Tags in the same manner as interchange e-Tags; and (6) the requirement on Balancing Authorities to ensure FERC access to e-Tags pertains to the Sink Balancing Authority and no other Balancing Authorities that may be listed on an e-Tag.

135 *Integration of Variable Energy Res.*, 141 FERC ¶ 61,232 (Dec, 20, 2012) ("*Order 764-A*"), *reh'g requested*.

136 *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246 (2012) ("*Order 764*"), *order on reh'g*, 141 FERC ¶ 61,232 (2012), *reh'g requested.*

137 *Id.* at P 15.

138 *Id.* at P 19.

139 *Id.* at P 23.

- **NOPR: Incorporation of WEQ Version 003 Standards (RM05-5)**

On July 18, the FERC issued a NOPR[140] which proposes to amend FERC regulations by incorporating by reference ***Version 003*** of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The Version 003 Standards update earlier versions of these standards previously incorporated by reference into FERC regulations at 18 CFR 38.2. The Version 003 standards include modifications to support Order Nos. 890, 890-A, 890-B and 890-C, including the standards to support Network Integration Transmission Service on an Open Access Same-Time Information System ("OASIS"), Service Across Multiple Transmission Systems ("SAMTS"), standards to support FERC policy regarding rollover rights for redirects on a firm basis, standards that incorporate the functionality for transmission providers to credit redirect requests with the capacity of the parent reservation and standards modifications to support consistency across the OASIS-related standards. The Version 003 Standards also include modifications to the OASIS-related standards that NAESB states support Order Nos. 676, 676-A, 676-E and 717 and add consistency. In addition, there are modifications to the Coordinate Interchange standards to compliment recent updates to e-Tag specifications, modifications to the Gas/Electric Coordination standards to provide consistency between the two markets, and re-organized and revised definitions to create a standard set of terms, definitions and acronyms applicable to all NAESB WEQ standards. The Version 003 Standards include the Standards addressed in *Order 676-G* and the recent Smart Grid Standards. Comments on the WEQ Version 003 Standards NOPR were due on or before September 24, 2013,[141] and were filed by 11 parties, including APPA, EEI, and the IRC. This matter is pending before the FERC.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jennifer Galiette (860-275-0338; jgaliette@daypitney.com).

- **NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On March 20, 2014, the FERC issued a series of orders addressing gas-electric coordination. At the forefront, was this NOPR, in which the FERC proposes to revise its natural gas act regulations in order to better coordinate the scheduling of natural gas and electricity markets and to provide additional flexibility to natural gas shippers.[142] Specifically, the NOPR proposes to: (i) start the Gas Day earlier, at 4:00 a.m. Central Clock Time ("CCT")[143] rather than 9:00 a.m., in order to ensure that gas-fired generators are not running short on gas supplies during the morning electric ramp periods; (ii) institute a later start to the first day-ahead gas nomination opportunity (called the Timely Nomination Cycle), from 11:30 a.m. to 1 p.m. The FERC said that because the Timely Nomination Cycle is the most liquid of the gas nomination cycles, this change will allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines; and (iii) modify the current intraday nomination timeline to provide 4 (rather than 2) intraday nomination cycles in order to provide greater flexibility to all pipeline shippers. The NOPR adds an early morning nomination cycle with a mid-day effective flow time and a new late-afternoon nomination cycle during which firm nominations would have precedence over or be permitted to bump already scheduled interruptible service. Ultimately, the standard cycles will be 8:00 a.m. CCT (bump), 10:30 a.m. CCT (bump), 4:00 p.m. CCT (bump) and 7:00 p.m. CCT (no-bump).

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[140] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, 144 FERC ¶ 61,026 (Jul. 18, 2013) ("*WEQ Version 003 Standards NOPR*").

[141] The *WEQ Version 003 Standards NOPR* was published in the *Fed. Reg.* on July 26, 2013 (Vol. 78, No. 144) pp. 45,096-45,104.

[142] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

[143] CCT, pursuant to the NAESB WGQ standards, reflects daylight savings changes.

To provide shippers additional flexibility, the NOPR also proposes to: (i) clarify its policy with respect to the "No-Bump" Rule for Pipelines with Enhanced Nomination Services (the ability of a pipeline to permit firm shippers to bump an interruptible shipper's nomination during any enhanced nomination opportunity proposed by the pipeline (beyond the standard nomination opportunities). The FERC indicated that under the revised intraday nomination timelines proposed here, pipelines offering enhanced nomination services should be permitted to bump interruptible shippers at least until the time when the bumping notice under the newly proposed Intra-Day 3 schedule is provided (in the Commission's proposal 6:00 p.m. CCT); and (ii) require Multi-Party Transportation Contracts; and (ii) FERC proposes to require all interstate pipelines to offer multi-party service agreements, providing multiple shippers the flexibility to share interstate pipeline capacity to serve complementary needs in an efficient manner.

Noting that the natural gas and electricity industries are best positioned to work out the details of how changes in scheduling practices can most efficiently be made and implemented, consistent with the policies discussed in the NOPR, the FERC provided the industries 6 months to reach consensus on standards, consistent with FERC's guidance in the NOPR, including any revisions or modifications to the proposals provided herein. Comments are due November 28, 2014[144] and should include the consensus standards or notifying the FERC of their inability to reach consensus on any revisions to the FERC's proposals. The FERC also noted its expectation that the electric industry (particularly the ISO/RTOs) would participate in these efforts to help ensure that the resulting consensus reasonably accommodates the interests of both industries.

On June 18, NAESB submitted a status report regarding its activities in response to Gas-Electric Scheduling Coordination NOPR. In that report, NAESB indicated that its efforts drew in nearly 500 active participants and over 700 participants monitoring the activity. NAESB further indicated that, although consensus on an alternative package incorporating all aspects of the proposals included in the NOPR was not reached during more than 8,000 straw and binding votes by the wholesale gas and wholesale electric market participants, the process resulted in commonalities that allowed the NAESB Board to move the process forward and request standards development in certain areas. Specifically, NAESB reported that those areas included standards related to the nomination deadline for the timely day-ahead scheduling of gas transportation, the nomination deadline of evening day-ahead scheduling of gas transportation and the nomination deadlines for scheduling intraday gas transportation through three cycles. Standards development will remain neutral on the gas day start time, as clear lines separated the positions of most of the wholesale gas and electric market participants. NAESB committed to provide to the FERC a status report and the record of its efforts by September 29, 2014.

- ***Order 787-A*: Gas/Electric Operational Info Sharing (RM13-17)**

As previously reported, the FERC issued, on November 15, 2013, its final rule revising its regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share nonpublic, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.[145] Recipients of the non-public, operational information will be subject to a No-Conduit Rule that prohibits subsequent disclosure of that information to an affiliate or third party. The approach to the sharing of non-public information proposed by the FERC is intentionally permissive, but the FERC noted that should this voluntary approach prove inadequate to promote reliable service or operational planning on natural gas pipelines and electric transmission systems, it may revisit the need to require certain communications or information sharing between transmission operators in the future. *Order 787* became effective December 23, 2013.[146] FERC-accepted changes to the ISO New England Information Policy that allow the ISO, consistent with *Order 787*, to share Confidential Information with interstate natural gas pipelines, were implemented on January 11, 2014.

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[144] The NOPR was published in the *Fed. Reg.* on Apr. 1, 2014 (Vol. 79, No. 62) pp. 18,223-18,243.

[145] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 145 FERC ¶ 61,134 (Nov. 15, 2013) ("*Order 787*"), *reh'g denied,* 147 FERC ¶ 61,228 (June 19, 2014)).

[146] *Order 787* was published in the *Fed. Reg.* on Nov. 22, 2013 (Vol. 78, No. 226) pp. 70,164-70,188.

On December 16, the Natural Gas Supply Association ("NGA"), Process Gas Consumers Group, and the Northwest Industrial Gas Users, as well as Enable Interstate Pipelines requested clarification and/or rehearing of *Order 787*. On June 19, 2014, in *Order 787-A*, the FERC denied those requests for clarification and/or rehearing.[147]

- **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**

Comments on the FERC's November 15, 2012 NOI seeking input on what changes, if any, should be made to the regulations under the natural gas market transparency provisions of section 23 of the Natural Gas Act ("NGA") are pending before the FERC. As previously reported, the FERC is considering the extent to which quarterly reporting of every jurisdictional natural gas transaction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency. Comments were received from over 40 parties.

- **Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442)**

Similar to the ISO/RTO 206 Order in EL14-22 et al. (*see* Section I above), the FERC also instituted a proceeding under Section 5 of the Natural Gas Act to examine whether interstate natural gas pipelines are providing notice of offers to purchase released pipeline capacity in accordance with section 284.8(d) of the Commission's regulations.[148] On or before May 19, natural gas pipelines must either revise their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrate that they are in full compliance with FERC regulations.[149] The FERC also requested that NAESB develop business practice and communication standards specifying: (1) the information required for requests to acquire capacity; (2) the methods by which such information is to be exchanged; and (3) the location of the information on a pipeline's website. Each pipeline must explain in its compliance filing how it will fully comply with 18 CFR § 284.8(d) until NAESB develops, and the FERC implements, the requested standards, including how the pipeline will provide shippers the ability to post offers to purchase capacity on the Informational Posting section of its website.[150]

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. Since the last report, there was gas-related enforcement activity in the following proceeding:

Company	***Alleged Violation(s)***	***Civil Penalty/Disgorgement***
BP America Inc. BP Corp. N. Amer. BP Amer. Production BP Energy Co. (together, "BP") (IN13-15)	The FERC established a hearing to determine whether BP violated section 4A of the Natural Gas Act and the FERC's Anti-Manipulation Rule as alleged by OE Staff. OE Staff alleged that BP traded physical natural gas at Houston Ship Channel ("HSC") to increase the value of BP's financial position at HSC, uneconomically using BP's transportation capacity, making repeated early uneconomic sales at HSC, taking steps to increase BP's market concentration at HSC. In doing so, OE staff alleged, BP suppressed the HSC Gas Daily	Show Cause Order[151] $28 million (civil penalty) $800,000 (disgorgement)

[147] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787-A, 147 FERC ¶ 61,228 (June 19, 2014) ("*Order 787-A*"),

[148] *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

[149] *Id.* at P 6.

[150] *Id.*

[151] *BP America Inc. et al.*, 144 FERC ¶ 61,100 (Aug. 5, 2013).

index with the goal of increasing the value of BP's financial position at HSC. The activity occurred from mid-September 2008 through November 2008.

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2013/14 Winter Reliability Program* (14-1104 and 14-1105)**
  Underlying FERC Proceedings: ER13-1851[152]
  Appellants: TransCanada and RESA, respectively

On June 6, 2014, TransCanada and the Retail Energy Supply Association filed petitions for review of the FERC's orders on the 2013/14 Winter Reliability Program.

- ***2013/14 Winter Reliability Program Bid Results* (14-1103)**
  Underlying FERC Proceedings: ER13-2266[153]
  Appellant: TransCanada

Also on June 6, 2014, TransCanada filed a petition for review of FERC's orders on the 2013/14 Winter Reliability Program Bid Results Filings.

- ***Orders 773* and *773-A* (2nd Cir., 13-2316)**
  Underlying FERC Proceedings: RM12-6 and RM12-7[154]
  Appellants: NY PSC and People of the State of New York

The NY PSC and the People of the State of New York have petitioned the Second Circuit Court of Appeals for review of FERC's orders on *Orders 773* and *773-A* (Revised "Bulk Electric System" Definition and Procedures). The brief of the NYPSC/State of NY was filed on May 2, 2014; NARUC's brief/joint appendix was filed on May 28, 2014.

- **New England's *Order 745* Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336[155]
  Appellants: EPSA and NEPGA

On July 16, 2012, EPSA and NEPGA filed a petition for review of FERC's orders on New England's *Order 745* (Demand Response Compensation) filings. On August 16, 2012, EPSA and NEPGA filed a statement of issues as well as an unopposed motion to hold case in abeyance pending the final resolution of Case Nos. 11-1486, et al. (*EPSA et al. v. FERC*) (*see* Orders 745 and 745-A below). On August 23, 2012, the

[152] 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

[153] 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

[154] 141 FERC ¶ 61,236 (Dec. 20, 2012); 143 FERC ¶ 61,053 (Apr. 18, 2013).

[155] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the course issuance of mandate in the *Order 745* appeal.

- **Orders 1000 and 1000-A (12-1232 consolidated with 12-1233, 12-1250, 12-1276, 12-1279, 12-1280, 12-1285, 12-1292, 12-1293, 12-1296, 12-1299, 12-1300, 12-1304, 12-1448, 12-1478, and 7th Cir. 12-2248)**
  Underlying FERC Proceedings: RM10-23[156]
  Appellants: SC PSA, Coalition for Fair Transmission, PSEG, and Sacramento Municipal Utility District

Petitions for review of FERC's Order 1000 and 1000-A, as identified in previous reports, remain pending before the DC Circuit in the consolidated proceedings identified above. Petitioners briefs were filed on May 28, 2013; Respondent's brief, September 25, 2013; Intervenors in Support of Respondent's Brief, October 16; and Reply Briefs, November 15. Final Briefs were filed on December 13, 2013. Also on December 13, 2013, an unopposed motion of Petitioners proposing format for oral argument was filed. In that motion, Petitioners proposed to waive oral argument on three of the eight issue-based briefs and contemplated oral argument solely on the issues in the remaining five briefs, divided into five sessions totaling 69 minutes per side. Respondent-Intervenors CLF et al. filed a response to Petitioners' motion and cross-motion for the allocation of three minutes of additional and separate time from that of the FERC to respond to Petitioners' and Supporting Intervenors' arguments on the issue of Transmission Planning and Public Policy. Oral arguments before Justices Rogers, Griffith and Pillard were held on March 20, 2014. Since the last report, in separate letters, counsel for Petitioner/Intervenors each argued that the DC Circuit's Decision vacating Order 745 (see 11-1486 below) undermined the FERC's case and supported theirs. This matter remains pending before the DC Circuit.

- **FCM Re-Design (12-1060 consolidated with 12-1074, 12-1085, and 12-1149) ****
  Underlying FERC Proceedings: ER10-787; EL10-57; EL10-50[157]
  Appellants: NEPGA, NSTAR, MMWEC/NHEC, VT DPS/VT PSB, NRG

Petitions for review of FERC's orders in the FCM Re-Design proceeding were filed by NEPGA on January 27, 2012; by NSTAR on February 3, 2012; by MMWEC/NHEC on February 10, 2012; by VT DPS/VT PSB on March 1, 2012; and by NRG on March 16, 2012. By orders dated February 7, 2012, February 27, 2012, March 2, and March 22, 2012, the Court consolidated the first four cases, with Case No. 12-1060 remaining the lead Case No. On February 29, 2012, the FERC filed an unopposed motion to hold the NEPGA, NSTAR, MMWEC/NHEC petitions in temporary abeyance pending expiration of the statutory deadline for the filing of petitions for review of the challenged orders. On May 7, 2012, NEPOOL notified the Court of its intent to be aligned as an intervenor in support of NSTAR (12-1074) and MMWEC/NHEC (12-1085), reserving the right to join in an intervenors' brief in support of those petitioners. On October 9, briefs were filed by MMWEC/NHEC, NSTAR, and NEPGA. Supporting petitions were filed on October 23 by NECPUC and PSEG. NEPOOL indicated that it would not join in any intervenor's brief. On January 7, 2013, FERC filed its Respondent Brief. Intervenor for Respondent Briefs were filed on January 22, 2013 by NEPGA and jointly by the CT PURA, HQ US, NICC, NSTAR, and NECPUC. Reply Briefs for Generator Petitioners and Distribution Utility Petitioners were filed on February 5, 2013. Final Briefs were submitted on March 5, 2013. Oral arguments were held on November 19, 2013 before Judges Sentelle, Brown and Griffith. This matter is now pending a decision of that panel.

- **Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)**
  Underlying FERC Proceedings: RM10-17-000[158]
  Appellants: EPSA, CAISO, ODEC, EEI, CA PUC

On May 23, 2014, in a 2-1 decision ("Decision"), the DC Circuit vacated *Order 745*[159] in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market". The DC Circuit

[156] 136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).

[157] 131 FERC ¶ 61,065 (Apr. 23, 2010); 132 FERC ¶ 61,122 (Aug. 12, 2010); 135 FERC ¶ 61,029 (Apr. 13, 2011); 138 FERC ¶ 61,027 (Jan. 19, 2012).

[158] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

vacated *Order 745* on two separate and independent grounds. First, it held that the FERC does not have jurisdiction to regulate demand response. The Court reasoned that: (i) the states retain exclusive authority to regulate the retail market; (ii) absent an express statutory grant of authority, the FERC cannot regulate areas left to the states; (iii) the FPA provides the FERC with authority over wholesale sales of electricity, but demand response is not such a sale; (iv) the authority of the FERC to regulate wholesale power rates under the FPA cannot be read so broadly as to allow direct regulation of demand response; and (v) demand response, while not necessarily a retail sale, is part of the retail market, involving retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption. Therefore, the Court concluded, the FERC has no authority to directly regulate demand response. "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."

As an alternative and secondary basis for its decision against *Order 745*, the Court concluded that the FERC order was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." The Court found that the FERC failed to reasonably consider and address arguments that *Order 745* will result in over-compensation of demand response resources, resulting in unjust and discriminatory rates. The Court further found that the FERC failed to demonstrate how its proposed pricing construct would result in just compensation. The Decision and preliminary implications of the Decision are summarized in more detail in the memo included with the supplemental materials circulated and posted for the June 6 meeting.

- **PPL EnergyPlus, LLC v. Nazarian (4th Cir., 13-2424)**

On June 2, 2014, the 4th Circuit Court of Appeals affirmed the September 30, 2013 decision of the United States District Court for the District of Maryland[160] which found that a Maryland Public Service Commission ("MD PSC") order directing three Maryland distribution utilities to enter into a 'contract for differences' for capacity and energy in the PJM control area (the "CfD") with a gas-fired merchant generator selected by the MD PSC (the "MD PSC Order") violated the Supremacy Clause of the United States Constitution and cannot be enforced.[161] In affirming the District Court decision, the 4th Circuit found the MD PSC Order both field[162] and conflict pre-empted.[163]

With respect to field pre-emption, the 4th Circuit stated that a "wealth of case law confirms FERC's exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged."[164] It found the federal scheme (i.e. the PJM Market) "carefully calibrated to protect a host of competing interests" (representing "a comprehensive program of regulation that is quite sensitive

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[159] *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

[160] *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 ("*District Court Decision*"). The *District Court Decision* was summarized in past Litigation Reports.

[161] *PPL EnergyPlus, LLC v. Nazarian*, 2014 U.S. App. LEXIS 10155.

[162] "Field preemption" is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be implied when federal law/regulation "occupies the field" in which the state is attempting to act/regulate. Field preemption occurs when there is "no room" left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

[163] "Conflict preemption" occurs where there is a conflict between a state law and a federal law. ("[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute."). Such a conflict occurs when "the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to "'the entire scheme of the statute'" and determine "'[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield."

[164] Slip op. at p. 14.

to external tampering"),[165] and leaving "no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result." Accordingly, the 4th Circuit concluded that the MD PSC Order "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction."[166] The MD PSC Order "compromises the integrity of the federal scheme and intrudes on FERC's jurisdiction" because the MD PSC Order "effectively supplants the rate generated by the auction with an alternative rate preferred by the state." The 4th Circuit rejected arguments that the CfD payments "represented a separate supply-side subsidy implemented entirely outside the federal market."[167] And, even if the presumption against preemption were to apply, the Court found that that it was "overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC."[168]

With respect to conflict pre-emption, the 4th Circuit found that the MD PSC Order "presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted".[169] Preemption was appropriate because of the "extensive and disruptive" impact of the MD PSC Order on matters within federal control (the PJM markets). It found that the MD PSC Order had "the potential to seriously distort the PJM's auction's price signals, thus 'interfer[ing] with the method by which the federal statute (i.e. the PJM Markets) was designed to reach its goals."[170] "Maryland's initiative disrupts [the PJM scheme] by substituting the state's preferred incentive structure for that approved by FERC."[171] "Maryland has sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible."[172]

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. On June 17, 2014, the 4th Circuit stayed the mandate pending the en banc ruling on the Petitions.

- **PPL EnergyPlus, LLC v. Hanna (3d Cir., 13-4330)**

The analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring unconstitutional (and therefore null and void) New Jersey's Long Term Capacity Agreement Pilot Program Act ("LCAPP"),[173] also summarized in previous reports, was appealed to the 3rd Circuit Court of Appeals. Amicus Curiae Briefs were filed by EEI/EPSA, PJM Power Providers Group, PA PUC; Reply Briefs by CPV, Hess and NJ BPU. APPA/NRECA and the FERC filed Amicus Curiae Briefs. Oral argument was held on March 27, 2014 and this matter is pending before the Third Circuit.

[165] *Id.* at p. 10.

[166] *Id.* at p. 16.

[167] *Id.* at pp. 18-19.

[168] *Id.* at p. 20. The Court noted the limited scope of its holding, which "is addressed to the specific program at issue" and did not "express an opinion on other state efforts to encourage new generation." *Id.* at p. 21.

[169] *Id.* at p. 27.

[170] *Id.* at p. 23.

[171] *Id.* at p. 24. ("Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.")

[172] *Id.* at p. 25.

[173] *PPL EnergyPlus, LLC v. Hanna*, __ F.Supp.2d ___ (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, ("*NJ Order*").

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