REPORT OF THE FINANCE & TRANSACTIONS COMMITTEE

The period covered by this report is December 2012 through December 2013.*

I. UPDATE ON SECTIONS 203 AND 205 OF THE FEDERAL POWER ACT (FPA)

A. Orders Denying Disposition of Jurisdictional Facilities

1. MACH Gen, LLC

On March 7, 2013, the Federal Energy Regulatory Commission (FERC or Commission) denied an application under section 203 (a)(1) of the FPA to approve the sale by MACH Gen, LLC (MACH Gen) of its outstanding membership interests in New Harquahala Generating Company, LLC (New Harquahala) to Saddle Mountain Power, LLC (Saddle Mountain).[1] The applicants acknowledged that absent any mitigation measures, the proposed transaction would result in the failure of the Commission's screens for horizontal market power.[2] Accordingly, the application presented a proposed mitigation plan to "eliminate the possibility that New Harquahala and its affiliates would have market power following the proposed transaction."[3] In a break with its expected practice, the Commission denied approval of the proposed transaction,

* The Finance & Transactions Committee acknowledges the substantial drafting contributions made to this Report by Zori G. Ferkin, Hilary Kao, and John Pappas.

1. *MACH Gen, LLC*, 142 F.E.R.C. ¶ 61,178 at P 1 (2013).
2. *Id.* at P 11.
3. *Id.* at P 14.

rather than conditionally accepting the transaction contingent upon further mitigation.[4] The Commission ruled that it was denying the application without prejudice to applicants making a new filing that proposes mitigation that would be sufficient to remedy the screen failures in its competition analysis.[5]

New Harquahala is the owner of the 1,054 megawatt (MW) Harquahala natural gas fired combined cycle facility located in the balancing authority area of Arizona Public Service Company (APS).[6] Saddle Mountain is a wholly owned subsidiary of an investment fund managed by Wayzata Investment Partners LLC (Wayzata).[7] Wayzata also indirectly owns two natural gas fired combined cycle generating units at the Gila River Facility, located within the same balancing authority area as the Harquahala facility.[8]

The application presented a delivered price test for the APS balancing authority area using both Economic Capacity and Available Economic Capacity.[9] Under the Economic Capacity analysis, the market is highly concentrated and the changes in the Herfindahl-Hirschman index (HHI) exceeded the Commission's threshold for seven of ten seasons/load periods.[10] Under the Available Economic Capacity analysis, HHI changes exceeded the Commission's threshold for seven of ten seasons.[11] As a result of the numerous screen failures, the applicants proposed a mitigation plan to "eliminate the possibility that New Harquahala and its affiliates would have market power following the proposed transaction."[12] The proposed mitigation plan would require New Harquahala to enter into an energy management agreement (EMA) with an independent third party, Twin Eagle Resource Management, LLC (Twin Eagle).[13] Under the EMA, Twin Eagle's responsibilities would "include the economic dispatch, marketing, and execution of short-term transactions for capacity and related energy products, scheduling transmission, administering settlement and payment for its transactions, procuring fuel and scheduling and tagging power."[14] Applicants claimed that under the EMA, New Harquahala would relinquish control to Twin Eagle of all available capacity and authority to dispatch the facility on a rolling twelve-month basis.[15] In addition, Twin Eagle would not provide New Harquahala any material, non-public information regarding sales and dispatch of the facility at a point when such information would provide a market advantage.[16] The EMA would limit Twin Eagle's ability to engage in transactions to the short-term markets.[17] New Harquahala

4. *Id.* at P 33.
5. *Id.*
6. *Id.* at P 3.
7. *Id.* at P 5.
8. *Id.*
9. *Id.* at P 12.
10. *Id.*
11. *Id.* at P 13.
12. *Id.* at P 14.
13. *Id.* at P 15.
14. *Id.* at P 17.
15. *Id.* at P 15.
16. *Id.* at P 22.
17. *Id.* at P 24.

also committed to only entering into long-term agreements for energy or capacity from the facility that would commence at least one year after the date of execution of such long-term agreements, and to submit any such long-term agreements to the Commission for approval prior to their commencement.[18]

The FERC, however, determined that the applicants "failed to show that the [p]roposed [t]ransaction [would] not have an adverse effect on competition within the APS [balancing authority area]."[19] The "large" and "dramatic" screen failures that the application presented, absent mitigation, were of particular concern because both the Harquahala and the Gila River facilities use combined cycle natural gas fired turbine generation technology.[20] "Under competitive conditions, each facility would have a similar dispatch cost and could be available at a similar point on the supply curve."[21] The FERC thus concluded that the mitigation measures were inadequate to address the potential adverse competitive effects of the transaction.[22] The FERC disagreed with the applicants that the proposed EMA would result in a complete transfer of control of the facility from New Harquahala to Twin Eagle.[23]

When considering whether to grant authority for market-based rates under section 205 of the FPA, the FERC has stated that EMAs "do not necessarily convey unlimited discretion and control away from the entity that owns the plant," but instead, "it is the totality of the circumstances that will determine which entity controls a specific asset."[24] The FERC applied a similar analysis in this section 203 proceeding and considered whether "the totality of the circumstances shows that the proposed EMA here conveys unlimited discretion and control to Twin Eagle such that the proposed mitigation sufficiently addresses the potential adverse impact on competition from the [p]roposed [t]ransaction."[25] "Importantly," the FERC stated, the EMA required Twin Eagle to follow a "detailed, proscribed" methodology for dispatching the facility, with little discretion to deviate; New Harquahala would establish the facility's operating limits, dispatch curves and operating costs; New Harquahala would retain responsibility for operation and maintenance of the plant; and New Harquahala would retain the right to enter into long term contracts for sales from

18. *Id.*

19. *Id.* at P 26.

20. *Id.* at PP 27-28.

21. *Id*. at P 27.

22. *Id.* at PP 32-33.

23. *Id.* at P 29.

24. *Id.* (citing Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252 at P 197, *clarified*, 121 F.E.R.C. ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, F.E.R.C. STATS. & REGS. ¶ 31,268, *clarified*, 124 F.E.R.C. ¶ 61,055, *order on reh'g*, Order No. 697-B, F.E.R.C. STATS. & REGS. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, F.E.R.C. STATS. & REGS. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, F.E.R.C. STATS. & REGS. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Public Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012)).

25. *Id.*

the plant.[26] These factors led the FERC to "find that New Harquahala retains a significant element of control over the Harquahala facility."[27]

The FERC also disagreed with the applicants' assertion that New Harquahala would not have access to non-public market information.[28] No other market participant would have advance knowledge of the short-term marketing strategy of the output of the facility; New Harquahala (or its affiliates) would be in a position, the FERC reasoned, to use that information in anticompetitive ways, such as withholding output from the Gila River facility or dispatching it at a higher price than would result from a competitive process.[29]

The FERC also concluded that New Harquahala's reserved right to market the capacity of the facility for long term contracts demonstrated that the facility would still be under New Harquahala's control "to some degree," and therefore the facility's capacity, even with the proposed mitigation plan, should continue to be attributed to New Harquahala for purposes of the Commission's horizontal competition analysis.[30]

2. Entergy Transfer of Transmission System to ITC

On June 20, 2013, the FERC approved under section 203 of the FPA the merger of Entergy Corporation's (Entergy) interstate transmission system with that owned by independent transmission company ITC Holdings Corp. (ITC Holdings or ITC).[31] Comments filed in the proceeding by the American Antitrust Institute indicated that ITC's acquisition of the Entergy transmission assets would make ITC Holdings the largest transmission company by load served and the second largest by line miles.[32] In separate dockets, the FERC approved the formula rates to be charged by the new ITC operating companies that would hold the Entergy transmission assets[33] and certain jurisdictional agreements submitted as part of the application, as well as other necessary service filings that will govern the operation of the new ITC operating companies within the Midwest Independent System Operator (MISO).[34] In the section 203 application, Entergy and ITC "request[ed] all necessary authorizations and approvals to enable the merger of [Entergy's] jurisdictional [transmission] assets . . . into ITC Midsouth, a newly-created subsidiary of ITC."[35] The Entergy jurisdictional transmission assets will be separated into six new "wires only" companies "that will ultimately become four new operating subsidiaries of ITC Holdings through a merger of Entergy Mid South, a new

26. *Id.* at P 30.

27. *Id.*

28. *Id.* at P 31.

29. *Id.*

30. *Id.* at P 32.

31. *ITC Holdings Corp.*, 143 F.E.R.C. ¶ 61,256 at P 4 (2013).

32. *Id.* at P 52.

33. Acceptance for Filing, *Clean Currents LLC Notice of Cancellation*, FERC Docket No. ER12-1681-000 (June 7, 2012).

34. *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 F.E.R.C. ¶ 61,258 at P 1 (2013); *Entergy Ark., Inc.*, 143 F.E.R.C. ¶ 61,259 at P 1 (2013).

35. *ITC Holdings*, 143 F.E.R.C. ¶ 61,256 at P 2.

Entergy subsidiary that will hold the 'wires only' operating companies, into ITC Midsouth."[36]

Beginning in 2006, Commission-approved agreements were implemented that put in place an Independent Coordinator of Transmission (ICT) for Entergy's transmission system.[37] The Southwest Power Pool served as Entergy's ICT until November 2012.[38] The ICT's responsibilities include independently administering Entergy's Open Access Transmission Tariff (OATT), conducting long-term transmission planning, serving as Reliability Coordinator for the Entergy transmission system, and overseeing Entergy's operation of a weekly procurement process for obtaining competitive energy supplies.[39] Pursuant to Commission approval, MISO assumed the role of ICT for Entergy on December 1, 2012.[40]

Under the proposed transaction, Entergy's transmission facilities would be owned by independent transmission companies not affiliated with any market participant engaged in the generation or marketing of wholesale or retail electricity or the ownership, operation, or control over inputs to electricity production.[41] The transmission facilities would be placed under MISO's functional control, increasing the amount of independently owned transmission within MISO.[42]

In analyzing the proposed transaction under section 203, the Commission found that the applicants were not required to submit studies demonstrating that the proposed transaction would not have an adverse effect on horizontal or vertical market competition, as the transaction did not involve generation assets or any affiliation with market participants, nor would the transaction create any new vertical combinations of assets.[43] The Commission was not persuaded to deviate from its precedent that anticompetitive effects are unlikely to arise from transactions that involve only the disposition of transmission facilities.[44]

The Commission also analyzed the effect of the proposed transaction on rates and considered whether any adverse effect would be offset or mitigated by the proposed transaction's likely benefits.[45] The Commission prefaced its analysis with the view that the proposed transaction presented "unique circumstances . . . in which the company currently holding the assets to be acquired is in the process of joining [a regional transmission operator (RTO)]."[46] The Commission did not agree with the intervenors' objections to Entergy's proposed return on equity in its formula transmission rates, because Entergy proposed the same return on equity that it would include in its rates as a result of

36. *Id.*
37. *Id.* at P 16.
38. *Id.* at P 17.
39. *Id.* at P 16.
40. *Id.* at P 17.
41. *Id.* at P 47.
42. *Id.*
43. *Id.* at P 59.
44. *Id.* at P 60.
45. *Id.* at P 118.
46. *Id.* at P 119.

transferring functional control of its transmission system to MISO and becoming a transmission-owning member of MISO.[47] As a transmission-owning member of MISO, Entergy's formula rates would be based upon the Commission-approved MISO return on equity, currently 12.38%.[48]

The Commission also considered the analysis in the application that showed that the proposed transaction would increase transmission rates for some customers due to the change in capital structure from Entergy's current capital structure to ITC's proposed capital structure targeting 60% equity and 40% debt.[49] The rate increases would vary from 1.4% to 8.1%, depending upon the state and pricing zone.[50] The Commission agreed, however, that those rate

> effects [would be] offset by the benefits of independent transmission company ownership over the Entergy transmission facilities[,] . . . a region that has not experienced the benefits of independent transmission ownership over and above any benefits that will result from Entergy's integration into MISO . . . and are benefits that are not attributable to Entergy's integration into MISO.51

The Commission considered comments challenging applicants' claims that the proposed capital structure would result in significant credit quality savings.[52] Even if applicants' estimates turned out to be overstated, the Commission said, the evidence provided by the applicants demonstrates that the expected benefits of the proposed transaction will likely offset the effect on rates.[53] Further, applicants had made "hold harmless" commitments that would hold customers harmless from transaction-related costs for five years.[54]

Under the merger agreement, Entergy may make an exchange trust election as "an option to help Entergy efficiently manage its post-transaction capitalization structure and improve cash flow and credit metrics."[55]

> [A]t least [thirty] days prior to the closing of the [p]roposed [t]ransaction, Entergy may elect to retain and subsequently transfer to . . . the Exchange Trust[an irrevocable trust,] the number of limited liability company membership common units in Entergy Mid South that would convert in the [p]roposed [t]ransaction to up to 4.99[%] of the total number of shares of [ITC] common stock outstanding immediately following consummation of the Proposed Transaction.[56]

"[U]pon delivery of notice by Entergy, the trustee of the Exchange Trust would conduct an exchange offer 'whereby Entergy shareholders may exchange Entergy common stock for the [ITC] common stock held by the [Exchange Trust].'"[57] "Until the time of the exchange offer, the shares of ITC Holdings common stock would be held in a trust managed by an independent third-party

47. *Id.* at P 121.
48. *Id.*
49. *Id.* at P 124.
50. *Id.* at P 65.
51. *Id.* at P 124.
52. *Id.* at PP 87, 89.
53. *Id.* at P 132.
54. *Id.*
55. *Id.* at P 161.
56. *Id.* at P 32.
57. *Id.*

trustee."[58] The applicants stated that "Entergy will have no ability to control or influence ITC Holdings in any respect as a consequence of the trust," and that "the trustee will be obligated to vote the shares that it holds in trust in the same proportion as all other ITC Holdings' shares are voted."[59] "No parties protested the proposed Exchange Trust election."[60] The Commission found the Exchange Trust election would not undermine or interfere with ITC's independence.[61]

The Commission also granted a request for a declaratory order that section 305(a) of the FPA is not a bar to the transaction.[62] Under section 305(a), it is

> unlawful for any officer or director of any public utility to receive for his own benefit, directly or indirectly, any money or thing of value in respect of the negotiation, hypothecation, or sale by such public utility of any security issued or to be issued by such public utility, or to share in any of the proceeds thereof, or to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account.[63]

The Commission agreed with Entergy that a key concern underlying the enactment of section 305(a) was "corporate officials . . . raiding corporate coffers for their personal financial benefit."[64] The applicants proffered a "Separation Plan" as a mechanism for separating Entergy's transmission assets and liabilities into the six "wires" subsidiaries, consolidation of the "wires" subsidiaries under Entergy Mid South, and distribution of Entergy Mid South common units to shareholders.[65] The Commission found that the source of any distribution in the Separation Plan had been clearly identified and that nothing indicated that the distribution would be excessive or preferential or impair the financial strength of any public utility.[66]

3. Ameren Energy Generating Company et al.

On October 11, 2013, the FERC approved a request for authorization under sections 203(a)(1) and 203(a)(2) of the FPA of a multi-step transaction in which Illinois Power Holdings, LLC (Illinois Power Holdings), a special purpose subsidiary of Dynegy Inc. (Dynegy), will acquire all of the equity interests indirectly owned by Ameren Corporation (Ameren) in a group of Ameren merchant utilities.[67] The Commission reviewed the proposed transaction under its merger policy statement, and authorized the transaction as consistent with the public interest.[68]

58. *Id.*
59. *Id.* at P 33.
60. *Id.* at P 162.
61. *Id.* at P 163.
62. *Id.* at P 178.
63. 16 U.S.C. § 825d(a) (2012).
64. *ITC Holdings*, 143 F.E.R.C. ¶ 61,256 at P 172.
65. *Id.* at P 171.
66. *Id.* at P 180.
67. *Ameren Energy Generating Co.*, 145 F.E.R.C. ¶ 61,034 at P 1 (2013).
68. *Id.*; *see generally* Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 F.E.R.C. ¶ 61,321 (1997) (Merger Policy Statement).

Even though the proposed transaction did not trigger screen failures under the Commission's competitive screen analysis, the Commission considered whether other evidence of anticompetitive effects had been presented.[69] The Commission concluded that there was no evidence of "anticompetitive effects that may be masked in the market concentration measures, and [that the intervenors did not provide] alternative evidence for the Commission to consider."[70] The Commission noted that because the proposed transaction consists almost entirely of baseload capacity, and "it is difficult from an operational perspective to withhold baseload generation because of the expense involved in doing so and because of the length of time it typically takes to ramp up and ramp down such generation," the Commission was further assured that the proposed transaction will not have an adverse effect on competition.[71]

The application included a sensitivity analysis in which the applicants assumed that 4,127 MW of coal-fired generation in the relevant geographic areas would be retired.[72] Certain intervenors argued that the applicants had not studied a sufficient amount of coal plant retirement scenarios.[73] The Commission did not agree and found that, based upon the record presented, the amount of possible coal plant retirements that the applicants considered in their analysis was a reasonable figure.[74] The Commission said that "[g]iven the wide range of estimates of retirements put forth in the record, the uncertain time frame over which those retirements will occur, and that those retirements are not directly impacted by the transaction," the applicants' estimates were reasonable.[75] Further, all of the generating capacity that would be subject to disposition in the proposed transaction is coal-fired.[76] If more coal plant retirements were assumed to occur, the result would be that the proposed transaction would continue to be "deconcentrating," under most season and load conditions in the Commission's competitive screen analyses.[77]

The Commission also considered the proposed transaction's effect on rates, and, consistent with its precedent, the Commission examined the effect of the proposed transaction on "captive customers."[78] For purposes of its section 203 regulations, the FERC defines "captive customers" as "any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation."[79] Certain municipal intervenors challenged the Commission's application of this definition of "captive customers" to its analysis of the effect on rates of a proposed transaction under section 203, arguing that when the

69. *Ameren*, 145 F.E.R.C. ¶ 61,034 at P 58.

70. *Id.*

71. *Id.*

72. *Id.* at P 57.

73. *Id.* at PP 48, 50.

74. *Id.* at P 57.

75. *Id.*

76. *Id.*

77. *Id.*

78. *Id.* at PP 84, 87.

79. *Id.* at P 84 (citing 18 C.F.R. § 33.1(b)(5) (2013)); *see also* Order No. 669, *Transactions Subject to FPA Section 203*, F.E.R.C. STATS. & REGS. ¶ 31,200 at P 166, 71 Fed. Reg. 1348 (2006) (codified at 18 C.F.R. pts. 2, 33).

Commission chose to single out captive customers in its section 203 analysis, it was speaking in the context of implementing its new cross-subsidization responsibilities under the Energy Policy Act of 2005, not to its precedent considering the effect on rates of a proposed transaction under its merger policy statement.[80] These intervenors argued that Commission precedent encompasses impacts on cost-based rates approved under market-based rate authority.[81] The Commission held that this was "incorrect."[82] The Commission acknowledged that it adopted the definition of "captive customers" in connection with implementing its new cross-subsidization responsibilities, but this action, it explained, simply applied its longstanding policy of protecting "captive customers who are served under cost-based rates that could be adversely affected by a section 203 transaction" to its implementation of the new cross-subsidization provisions of section 203(a)(4), as amended by the Energy Policy Act of 2005 since those provisions are "rooted in similar concerns."[83] The Commission also rejected the argument that market-based rates based on a cost-of-service formula constitute "cost based regulation" within the meaning of its definition of "captive customer" for purposes of considering the effect of a proposed transaction on rates under section 203.[84] "The fact that parties to a transaction entered into under market-based rate authority negotiate a price that is equal to cost does not mean that the customer is thereby being served under cost-based regulation."[85]

4. Nevada Power Co.

The proposed transaction in *Nevada Power Co.* triggered screen failures under the Commission's competitive market screen analysis.[86] Nevertheless, the Commission granted the application, authorizing Nevada Power to acquire the California Department of Water Resources' (CDWR) 67.8% ownership interest in Unit No. 4 of the Reid Gardner Station, a 257 MW (net) coal-fired generating facility located near Moapa, Nevada.[87] "Nevada Power currently owns the remaining 32.2[%] interest in Unit 4."[88] The Commission cited specific factors that, taken together, demonstrated that Nevada Power would not have the ability and incentive to withhold output in order to drive up the market price.[89] First, the coal-fired generation being acquired is baseload capacity and, therefore, the Commission stated, "difficult and uneconomic to withhold."[90] "Second, Nevada Power is required to fully credit any profits from wholesale sales to retail customers through a fuel adjustment clause, removing any incentive for Nevada

80. *Ameren*, 145 F.E.R.C. ¶ 61,034 at P 86.
81. *Id.*
82. *Id.*
83. *Id.* at P 87.
84. *Id.* at P 88.
85. *Id.*
86. *Nevada Power Co.*, 145 F.E.R.C. ¶ 61,022 at P 13 (2013).
87. *Id.* at PP 1-2.
88. *Id.* at P 1.
89. *Id.* at P 27.
90. *Id.*

Power to . . . exercise market power [to raise prices] because the seller will not receive any benefit from the additional revenue received from manipulating market prices."[91] Third, "the proposed transaction will not result in the elimination of a competitor, since CDWR has not sold into" the relevant balancing authority areas.[92] Fourth, Nevada Power has a contractual right to call upon the entire output of Unit 4 as peaking capacity for up to 1500 hours each year.[93] The existence of this contractual right, the Commission found, suggested that Nevada Power already has significant control over the output of Unit 4 during peak periods, "further diminishing the potential of the proposed transaction to have an adverse impact on horizontal competition."[94]

II. LIQUEFIED NATURAL GAS (LNG) EXPORT AUTHORIZATIONS

In 2013, the U.S. Department of Energy (DOE) ended a year long hiatus in issuing authorizations to export volumes of liquefied natural gas (LNG) to countries with which the United States does not have in place a free trade agreement (so-called "non-FTA" countries).[95] As debt and equity parties consider potential transactions for financing of liquefaction treatment plants and natural gas supply pipelines for the export markets, the following will highlight certain specific issues associated with such potential investments.[96]

One issue that was addressed in 2013 with respect to the DOE approval process for exports of LNG to non-FTA countries is revocation risk—the possibility that changes in the DOE's assessment of the impacts on natural gas markets might lead the DOE to revoke or rescind an export approval.[97] In Order No. 3282, in which the DOE conditionally authorized Freeport LNG Expansion LP and FLNG Liquefaction LLC (collectively, FLEX) to export LNG to non-FTA countries, the DOE stated that it will monitor the market and the impact of LNG exports and may "issue, make, amend, and rescind such orders . . . as it may find necessary" but cautioned that it "cannot precisely identify all the circumstances under which such actions may be taken."[98]

On August 2, 2013, Chairman of the Senate Committee on Energy and Natural Resources, Senator Ron Wyden (D-OR), and ranking member Senator Lisa Murkowski (R-AL) sent a letter to the Secretary of Energy, Ernest Moniz, identifying this issue and requesting clarification of the circumstances under which the DOE might revoke or modify an export authorization.[99] In the letter

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91. *Id.* at P 28.

92. *Id.* at P 29.

93. *Id.*

94. *Id.*

95. *Energy Department Authorizes Second Proposed Facility to Export Liquefied Natural Gas*, U.S. DEP'T ENERGY (May 17, 2013, 12:00 PM), http://energy.gov/articles/energy-department-authorizes-second-proposed-facility-export-liquefied-natural-gas.

96. Freeport LNG Expansion, L.P., Order No. 3282, FE Docket No. 10-161, at 112 n.126 (Dep't of Energy May 17, 2013).

97. *Id.*

98. *Id.* (quoting Sabine Pass Liquefaction, LLC, Order No. 2691, FE Docket No. 10-111, at 33 n.45 (Dep't of Energy Aug. 7, 2012)).

99. Letter from Sen. Ron Wyden, Chairman, & Sen. Lisa Murkowski, Ranking Member, S. Comm. on Energy & Natural Res., to Ernest Moniz, Sec'y Dep't of Energy (Aug. 2, 2013) [hereinafter Letter to Sec'y

they point to two sources of authority.[100] The first is the Natural Gas Act (NGA), which empowers the DOE to "amend, and rescind such orders . . . as it may find necessary or appropriate to carry out the provisions of [the NGA]."[101] The second is the Energy Policy and Conservation Act of 1975 (EPCA), which may provide the DOE authority to revoke or substantially modify previously authorized export licenses as the president determines appropriate and necessary.[102]

In the DOE's response dated October 17, 2013, Deputy Assistant Secretary Paula Gant stated, first, that the DOE "would not rescind a previously-granted authorization except in the event of extraordinary circumstances" and that the DOE "takes very seriously the investment-backed expectations of private parties."[103] Second, Ms. Gant stated that the DOE has never vacated or rescinded an authorization to import or export natural gas over the objections of the authorization holder.[104] Such authorizations have only been rescinded when the authorization holder requested the authorization be vacated, had gone out of business, or was non-responsive to the DOE's inquiries.[105] Third, she stated that the DOE would not consider the cumulative impact of other authorizations when deciding whether to rescind an authorization.[106] Fourth, "with respect to final orders that are no longer subject to judicial review, . . . [n]either the NGA nor DOE regulations limit the submission of a request to suspend or revoke a final order to parties in the prior authorization proceeding."[107]

While the DOE has not stated that there is a cap on the amount of LNG it will approve to export to non-FTA countries, its decisions in 2013 did not always grant to applicants authorization to export the requested quantity of LNG exports.[108] The DOE on May 23, 2013, granted FLEX authorization to export 1.4 billion cubic feet per day (Bcf/d) to non-FTA countries.[109] The DOE did not grant a second FLEX request, filed December 19, 2011, to export an additional 1.4 Bcf/d to non-FTA countries, and instead only conditionally authorized the export of 0.4 Bcf/d to non-FTA countries from the Freeport LNG Terminal.[110] The DOE based its determination on the Freeport project's application to the

Moniz], *available at* http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=fcd19e75-9ff9-4d75-aa4e-7330b5f8b03f.

100. *Id.* at 1.

101. *Id.*; *see generally* Natural Gas Act §§ 3(a), 16; 15 U.S.C. §§ 717b, 717*o* (2013).

102. Letter to Sec'y Moniz, *supra* note 99; *see generally* Energy Policy and Conservation Act of 1975, 42 U.S.C. §§ 6201-6422 (2012).

103. Letter from Paula A. Gant, Deputy Assistant Sec'y, Dep't of Energy Office of Oil & Natural Gas, to Sen. Lisa Murkowski 1 (Oct. 17, 2013), *available at* http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=9e99e412-ce05-449d-8893-dc8d64c32d02.

104. *Id.*

105. *Id.*

106. *Id.*

107. *Id.*

108. Freeport LNG Expansion, L.P., Order No. 3282, FE Docket No. 10-161, at 120 (Dep't of Energy May 17, 2013).

109. *Id.*

110. Freeport LNG Expansion, L.P., Order No. 3357, FE Docket No. 10-161, at 162 (Dep't of Energy Nov. 15, 2013).

FERC for authorization to construct the liquefaction facilities, which referred to 1.4 Bcf/d as the capacity of the liquefaction project.[111]

III. QUALIFYING FACILITIES UPDATE

The 2013 filing year saw a number of actions before the Commission with respect to the treatment of small power production facilities and cogeneration facilities, each of which is relevant to the financing and contracting abilities of such qualifying facilities (QFs, as discussed below). During the 2013 filing year, the Commission received several petitions from QFs for enforcement action pursuant to section 210(h) of the Public Utility Regulatory Policies Act of 1978 (PURPA).[112] Part A below describes the Commission's treatment of an Idaho PUC regulation with regard to the enforceability of power purchase agreements (PPAs) between QFs and utilities. Part B describes a renewable energy credit (REC) allocation dispute, again involving the Idaho PUC. Part C looks at the FERC's consideration of whether a QF can be paid at one state's avoided cost rates while delivering power to a utility in another state. Part D involves a dispute in Minnesota over its rule on calculating avoided costs and whether it is consistent with PURPA. Part E addresses Montana's competitive solicitation process for QFs, or lack thereof. Finally, Part F describes challenges brought to California's and Vermont's feed-in tariff programs, in particular as they relate to small renewable generators.

A. Grouse Creek Wind Park, Cedar Creek Wind, Rainbow Ranch Wind, and Murphy Flat Power

In 2012, the Commission considered three separate actions involving the Idaho Public Utilities Commission (PUC). *Cedar Creek*,[113] *Rainbow Ranch*,[114] and *Murphy Flat*[115] focused on the Idaho PUC's "bright line" rule that PPAs between QFs and utilities would not be considered legally enforceable if not fully executed by both parties by December 14, 2010.[116] In the third case, *Murphy Flat*, the FERC stated its intention to take enforcement action against the Idaho PUC if it continued to adhere to its "bright line" rule.[117]

On December 29, 2010, Idaho Power Company (Idaho Power) submitted to the Idaho PUC for approval two long-term PPAs with Grouse Creek Wind Park, LLC and Grouse Creek Wind Park II, LLC (collectively, Grouse Creek).[118] In June 2011 and in September 2012, the Idaho PUC rejected the Grouse Creek

111. *Id.*

112. 16 U.S.C. § 824a-3 (2012).

113. *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011).

114. *Rainbow Ranch Wind, LLC*, 139 F.E.R.C. ¶ 61,077 (2012).

115. *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 (2012).

116. *See generally Report of the Finance & Transactions Committee*, 34 ENERGY L.J. 421, 431 (2013) (Section V.C. described the *Cedar Creek Wind*, *Rainbow Ranch Wind*, and *Murphy Flat Power* enforcement actions).

117. *Murphy Flat*, 141 F.E.R.C. ¶ 61,145 at P 29 (2012). "The Commission order[ed]: (A) Notice is hereby given that the Commission will initiate an enforcement action under section 210(h)(2)(A) of PURPA." *Id.*

118. *Grouse Creek Wind Park, LLC*, 142 F.E.R.C. ¶ 61,187 at P 4 (2013).

PPAs, on the basis that they had been executed after December 14, 2010.[119] On January 15, 2013, Grouse Creek filed a petition for enforcement with the Commission seeking the same relief as set forth in the Commission's orders in *Cedar Creek*, *Rainbow Ranch*, and *Murphy Flat*.[120] Grouse Creek asserted that because the material terms of its PPAs with Idaho Power were negotiated prior to December 14, 2010, the PPA gave rise to a legally enforceable obligation under PURPA[121] and that the Idaho PUC's June 2011 and September 2012 orders were inconsistent both with PURPA and with the Commission's orders in *Cedar Creek*, *Rainbow Ranch*, and *Murphy Flat*.[122]

The Commission issued an order on March 15, 2013, stating the Idaho PUC's June 2011 and September 2012 orders were inconsistent with PURPA as well as the Commission's regulations, and initiating an enforcement action against the Idaho PUC—the first ever enforcement action against a state utility commission by the FERC.[123] The Commission stated that "given the [Idaho PUC's] reliance on its 'bright line rule' in its June 8 decision and additional barriers to establishment of legally enforceable obligations in its September 7 decision, despite the Commission's orders in *Cedar Creek* and *Rainbow Ranch*, we intend to go to court to enforce PURPA."[124]

Commissioner Tony Clark issued a separate dissent,[125] stating "[t]he Commission's initiation of a parallel federal process on behalf of a plaintiff with an ongoing case in the State Supreme Court of Idaho demonstrates the results that occur when the Commission departs from the principles of judicial economy and long established regulatory precedent."[126]

In the first action of its kind under PURPA, on March 22, 2013, the Commission commenced litigation in the U.S. District Court, District of Idaho seeking (i) a ruling that the Idaho PUC June 8, 2011, and September 7, 2012, orders violate PURPA and the FERC's implementing regulations and (ii) to enjoin the Idaho PUC from imposing conditions precedent on the formation of legally enforceable obligations in a manner inconsistent with PURPA, the

119. *Id.* at PP 6, 11.

120. *Id.* at P 13.

121. 16 U.S.C. § 824a-3 (2012).

122. Petition for Enforcement of the Public Utility Regulatory Policies Act of 1978 at 1-4, *Grouse Creek*, 142 F.E.R.C. ¶ 61,187 (2013) (Docket No. EL13-39-000) (requesting the FERC "initiate an enforcement action against the Idaho PUC for having impermissibly held that Idaho Power did not incur legally enforceable obligations to purchase, and that the Grouse Creek Parties had no right under PURPA to charge, the then-effective published avoided cost rates, until both parties executed the Agreements").

123. *Grouse Creek*, 142 F.E.R.C. ¶ 61,187 (stating in its order, "(A) Notice is hereby given that the Commission will initiate an enforcement action under section 210(h)(2)(A) of PURPA, in conjunction with the Commission's enforcement action in Murphy Flat.").

124. *Id.* at P 35. The FERC held that the facts in *Grouse Creek* were substantially similar to the facts in the three other actions, thus explaining why the *Grouse Creek* enforcement action would be taken in conjunction with the *Murphy Flat* enforcement action. *Id.* at PP 35-36.

125. Commissioner Clark issued a separate dissent in *Grouse Creek* which reiterated his concerns from his dissent in *Murphy Flat*. He did not believe it was prudent or consistent with long-standing FERC policy to intervene directly against a state commission on behalf of a private developer. In the instant case, Commissioner Clark was also concerned about the Commission's taking action in federal court when the developer already had a state action pending. *Id.* at 19 (Clark, Comm'r, dissenting).

126. *Id.*

FERC's regulations and the *Murphy Flat* and *Grouse Creek* orders.[127] Some commentators questioned whether the FERC would be successful in its enforcement action or whether the FERC was overreaching[128] while the National Association for State Utility Commissions (NARUC) expressed disappointment at the FERC's enforcement action.[129]

The Commission and the Idaho PUC were able to settle the litigation.[130] On December 24, 2013, the FERC and the Idaho PUC entered into a Memorandum of Understanding (MOU) and moved to dismiss the pending federal case.[131] Under the MOU, "[t]he Idaho PUC acknowledges that a legally enforceable obligation may be incurred prior to the formal memorialization of a contract to writing."[132] The settlement was well received by some[133] but has not necessarily resolved the developers' disputes with the Idaho PUC, as they are left to pursue their claims in state court.[134]

In Grouse Creek's case, it concurrently sought relief in state court.[135] Grouse Creek's state court case was also resolved in December 2013, in favor of the Idaho PUC.[136] The Idaho Supreme Court ruled that the Idaho PUC's rejection of Grouse Creek's PPAs with Idaho Power was not arbitrary and

127. Complaint at 20, FERC v. Idaho Pub. Utils. Comm'n, No. 1:13-cv-141 (D. Idaho Mar. 22, 2013).

128. Scott Grover, *FERC Sues State Commission for PURPA Failings*, 28 NAT. RESOURCES & ENV'T 48, 50 (2013). "Ultimately, the [Idaho PUC] Complaint may prove to be just another fruitful dustup in the nation's storied history of federal/state relations. A fair view of the context—including that giving rise to FERC's enforcement action as well as the background generally—suggests that more may be at play." *Id.*

129. Press Release, NARUC, Utility Regulators 'Deeply Disappointed' in FERC Litigation Against Idaho PUC (Mar. 27, 2013), *available at* http://www.naruc.org/news/default.cfm?pr=366&pdf. NARUC President P. Jones stated:

> We are deeply disappointed in the Federal Energy Regulatory Commission's action in this case. It is not at all clear why FERC would take this drastic and unprecedented step at this time. Historically FERC has allowed the parties in such a dispute to resolve their differences either through settlement or litigation between the parties themselves.

Id.

130. *See generally* Memorandum of Understanding Between the FERC and the Idaho PUC (Dec. 24, 2013), *available at* http://www.ferc.gov/legal/mou/mou-idaho-12-2013.pdf; *see also* Press Release, FERC, FERC, Idaho PUC Sign Agreement on PURPA (Dec. 24, 2013), *available at* http://www.ferc.gov/media/news-releases/2013/2013-4/12-24-13.pdf (highlighting their interest in implementing PURPA in a spirit of cooperation and in a regime of cooperative federalism).

131. Memorandum of Understanding, *supra* note 130.

132. *Id*.

133. Press Release, NARUC, NARUC's Honorable Lauds FERC-Idaho PUC Agreement on PURPA Dispute (Dec. 26, 2013), *available at* http://www.naruc.org/News/default.cfm?pr=409. NARUC President C. Honorable stated, "I want to applaud the Idaho Public Utilities Commission and the Federal Energy Regulatory Commission for signing this agreement. In particular I want to thank FERC Chair Cheryl LaFleur and Idaho PUC Chair Paul Kjellander." *Id.*

134. Rocky Barker, *Idaho PUC, FERC Settle and Idaho Supreme Court Backs PUC in Wind Case*, IDAHO STATESMAN BLOGS (Dec. 30, 2013), http://blogs.idahostatesman.com/idaho-power-ferc-settle-and-idaho-supreme-court-backs-puc-in-wind-case/#storylink=cpy ("'I am disappointed that FERC has left these projects out in the cold,' said Peter Richardson, an attorney who represents wind producers. 'It will be very difficult for them to fend for themselves against the litigation power of the State of Idaho.'"); *see also*, Esther Whieldon, *FERC Withdraws PURPA Suit Against Idaho PUC After Both Agree to Collaborate More*, SNL FINANCIAL, Dec. 26, 2013.

135. Idaho Power Co. v. Idaho Pub. Utils. Comm'n, 316 P.3d 1278 (Idaho Sup. Ct. 2013).

136. *Id.*

capricious, that the PPAs' execution date after December 14, 2010, was an acceptable basis for rejection of the contracts, and that PURPA did not require the Idaho PUC to accept the avoided cost rates requested in the PPAs.[137] While the decision was unanimous, Justice Jones' separate concurrence expressed concern about the Idaho PUC's departure from past practice in approving other PPAs, as well as the Idaho PUC's seemingly inconsistent orders.[138]

B. Clearwater Paper Corporation

In September 2013, Clearwater Paper Corporation (Clearwater Paper) filed a petition requesting that the FERC initiate an enforcement action against the Idaho PUC pursuant to section 210(h) of PURPA.[139] Clearwater Paper asserted that two of the Idaho PUC's orders[140] impermissibly relied upon PURPA "as the sole basis for creating and then allocating ownership of RECs associated with generation from certain Idaho [QFs] to utilities, at no payment other than avoided cost."[141]

Clearwater Paper's petition purports to be the first case concerning allocation of RECs in a jurisdiction that has not adopted a renewable portfolio standard or otherwise created RECs under state law.[142] The petitioner argues that the Idaho PUC's orders and allocation of RECs 50/50 between investor and utility at the avoided cost rate is in conflict with PURPA and the FERC's orders on several different fronts, including (i) the Idaho PUC's reliance on PURPA to create RECs, rather than on state law, and (ii) the lack of compensation to QFs for RECs other than at their existing avoided cost rates, which is improper as avoided costs capture only energy and capacity charges and QFs have conditions placed on their ability to exercise rights under PURPA.[143] Clearwater Paper asserts that the Idaho PUC erred because "a utility's sale of RECs produces revenue which directly offsets the cost of purchasing power from the QF and provides a tangible benefit to ratepayers."[144] Clearwater Paper notes that RECs would not exist but for PURPA and, furthermore, are not attributes that transfer with the contract absent any state law provision providing this action and absent any compensation.[145]

The FERC declined to commence an enforcement action against the Idaho PUC in this matter on November 19, 2013, and noted the petitioner was free to pursue remedies in state court.[146]

137. *Id.* at 1279, 1286, 1288.

138. *Id.* at 1289, 1291 (Jones, J., concurring).

139. Petition for Enforcement Pursuant to PURPA Section 210(h) at 1, *Clearwater Paper Corp.*, FERC Docket No. EL13-91-000 (Sept. 20, 2013).

140. *Id.* at 1 & nn.2-3 (discussing Commission's Review of PURPA QF Contract Provisions for Calculating Avoided Cost Rates, Order No. 32802, Case No. GNR-E-11-03 (Idaho P.U.C. May 6, 2013) [hereinafter IPUC Order No. 32803]; *Commission's Review of PURPA QF Provisions*, Order No. 32697, Case No. GNR-E-11-03 (Idaho P.U.C. Dec. 18, 2012) [hereinafter IPUC Order No. 32697]).

141. *Id.* at 1.

142. *Id.* at 1-2.

143. *Id.* at 2.

144. *Id.* at 13 (citing IPUC Order No. 32802, *supra* note 140, at 12-13).

145. *Id.* at 9-10.

146. Notice of Intent Not to Act, *Clearwater Paper Corp.*, 145 F.E.R.C. ¶ 61,140 at P 2 (2013).

C. Kootenai Electric Cooperative

Kootenai Electric Cooperative, Inc. (Kootenai) owns and operates the Fighting Creek Landfill Station, a self-certified QF located in Idaho with a capacity of just over 3 MW.[147] In April 2013, Kootenai came before the Commission with a section 210(h) petition because it sought to enter into a PPA with Idaho Power that would be subject to the terms of Oregon's avoided cost rates for QFs.[148]

Kootenai submitted a request to Avista Corporation for firm long-term point-to-point transmission service for 3 MW of reserved capacity on the Lolo-Oxbow 230 kilovolt (kV) transmission line running from Oregon to Idaho with a point of delivery at the LOLO scheduling point.[149] This matter came before the Commission in 2012 when Kootenai sought clarification on the change of ownership between Avista Corporation and Idaho Power to be specified as Imnaha, Oregon.[150] The Commission ruled that "Avista's description of the [point of delivery (POD)] provides Kootenai non-discriminatory transmission service all the way across Avista's transmission system;" however, the Commission did not require Avista to modify the transmission agreement submitted by Avista to specifically reference Imnaha, Oregon.[151]

Kootenai originally sought clarification with respect to the transmission agreement because it wished to sell power to Idaho Power.[152] Kootenai had originally sought to enter into a PPA in 2011 with Avista under Idaho's rules implementing PURPA but was unable to reach agreement with Avista because Avista sought to include a clause impairing Kootenai's clear title to ownership of the RECs associated with Fighting Creek.[153] Kootenai did not wish to get embroiled in the Idaho Power and Idaho PUC disputes with QFs concerning when legally enforceable obligations arise, so it considered other options.[154] Kootenai determined that it could wheel power across Avista's Lolo-Oxbow transmission and deliver to Idaho Power in Eastern Oregon, where Idaho Power provides service.[155] Kootenai also determined that Oregon's rules implementing PURPA did not impose restrictions on RECs, and the RECs would thus remain with the QF.[156] Kootenai sought to enter into an Oregon PPA with Idaho Power,

147. Petition for Declaratory Order Pursuant to Rule 207 and Petition for Enforcement Pursuant to PURPA Section 210(h) at 4, *Kootenai Elec. Coop., Inc.*, FERC Docket No. EL13-59-000 (Apr. 16, 2013).

148. *Id.* at 1.

149. *Id.* at 2.

150. *Avista Corp.*, 140 F.E.R.C. ¶ 61,165 at P 8 (2012).

151. *Id.* at P 21.

152. *Id.* at P 5.

153. Petition, *supra* note 147, at 4. Kootenai was unable to agree to any assignment of title to RECs as it was not the sole owner of these attributes and therefore was unable to assign title as requested by Avista. The issue of ownership of REC attributes is discussed *supra* in Part III.B.

154. *Id.* at 4-5 (citing *Grouse Creek Wind Park LLC*, 142 F.E.R.C. ¶ 61,187 (2013); *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 (2012); *Rainbow Ranch Wind, LLC*, 139 F.E.R.C. ¶ 61,077 (2012), and *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011) as examples demonstrating that "QFs have generally had difficulty in obtaining the IPUC's assistance in enforcing rights to a LEO over a utility's objection," *id.* at 5 n.8).

155. *Id.* at 5.

156. *Id.*

but Idaho Power protested under Idaho PUC provisions.[157] After Kootenai submitted an Oregon PPA to Idaho Power and to the Oregon PUC, the Oregon PUC also objected on the grounds that power would be delivered in Idaho at the substation, rather than in Oregon at the change of ownership in the transmission line.[158]

The Commission issued an order on June 14, 2013, and indicated it would not take an enforcement action against the Oregon PUC.[159] However, the Commission held that the Oregon PUC misinterpreted the Commission's August 31, 2012, order concerning Kootenai's right to nondiscriminatory transmission service and further held that the Oregon PUC's February 26, 2013, order (Oregon Order) is inconsistent with PURPA because it precludes Kootenai from selling its Fighting Creek QF facility output in Oregon.[160] The Commission held that a

> QF has the discretion to choose to sell to a more distant utility (as it has here), and thus where to sell, as long as the QF can deliver its power to the utility. A sale at Imnaha, Oregon would allow Kootenai to receive Oregon Commission-approved avoided cost rates under PURPA. The Oregon Order violates Kootenai's PURPA rights to choose whether to sell the Fighting Creek QF output at Oregon Commission-approved avoided cost rates by delivering such output at the point where Avista's and Idaho Power's transmission systems interconnect. A utility is obligated under PURPA to purchase the output of a QF as long as the QF can deliver its power to the utility.[161]

D. Gadwall Wind LLC

Shifting focus from the Northwest to the Midwest, Gadwall Wind LLC (Gadwall) petitioned the FERC on March 15, 2013, to initiate an enforcement action against the Minnesota PUC pursuant to section 210(h)(2)(A) of PURPA or, in the alternative, to find that a Minnesota statute concerning calculation of avoided costs is inconsistent with the requirements of PURPA.[162] Gadwall took the position that the Minnesota PUC improperly applied PURPA's requirement that a utility pay a new QF at its full-avoided cost.[163] Gadwall asserted that under the Minnesota statute in question, a QF "is only entitled to receive the lowest of (i) the actual avoided costs, (ii) the utility's least cost renewable energy facility (regardless of when placed in service), and (iii) the bid of a competing supplier of a least cost renewable energy facility."[164] Gadwall argued that the Minnesota statute does not comply with the FERC's Order No. 69, which provides that an avoided cost rate for a utility is to be "determined by reference

157. *Id.* at 7.

158. *Id.* at 20.

159. *Kootenai Elec. Coop., Inc.*, 143 F.E.R.C. ¶ 61,232 at P 1 (2013).

160. *Id.*

161. *Id.* at P 33. The Commission further agreed with Kootenai that upholding Oregon's Order would have the effect of requiring Kootenai to pay for reservation and line loss costs all the way to Imnaha, Oregon, under Avista's OATT but denying Kootenai the ability to sell to Oregon by terminating this transaction at the Lolo substation in Idaho. *Id.* at P 32.

162. Petition for Enforcement Under PURPA at 1, 3, *Gadwall Wind, LLC*, FERC Docket No. EL13-54-000 (Mar. 15, 2013); *see generally* 18 C.F.R. § 292.304(a)(4) (2013) (PURPA's avoided cost rate calculation).

163. Petition, *supra* note 162, at 1.

164. *Id.* at 3.

to the highest marginal cost unit or future expansion that would be avoided."[165] Gadwall sought FERC action to invalidate subdivision 4 of Minnesota statute section 216B.164 as inconsistent with implementation of PURPA.[166]

The FERC declined to take enforcement action in its order issued December 19, 2013.[167] The FERC stated that its decision not to initiate an enforcement action "means that the [p]etitioner may itself bring an enforcement action against the Minnesota Commission in the appropriate court."[168] The FERC also declined to take a position on whether the Minnesota statute in question is inconsistent with PURPA.

E. Hydrodynamics, Inc.

Hydrodynamics Inc., Montana Marginal Energy, Inc., and WINData, LLC (collectively, Petitioners) petitioned the Commission on June 17, 2013, to institute an enforcement action or issue a declaratory order finding that the Montana Public Service Commission's (MPSC) rule, section 38.5.1902(5) of the Administrative Rules of Montana (the MPSC Rule), fails to implement PURPA and eliminates the rights of QFs to (1) create legally enforceable obligations (LEOs) and (2) choose how to sell energy and capacity.[169] The Petitioners sought the Commission's clarification "that a QF's right to create [an] LEO is not dependent on the competitive solicitation process—rather, a QF may either win a competitive solicitation or create [an] LEO outside the competitive solicitation process, particularly if such competitive solicitations are not regularly conducted."[170]

This petition remains pending. In addition to the routine intervenors, the MPSC and NorthWestern Corporation,[171] the Edison Electric Institute (EEI), and the NARUC also filed motions to intervene.[172] The MPSC and fellow intervenors vigorously defend MPSC's rules for a competitive solicitation process, including a 50 MW cap for NorthWestern Corporation.[173]

165. *Id.* at 9.

166. *Id.* at 10.

167. *Gadwall Wind LLC v. Minnesota Pub. Utils. Comm'n*, 145 F.E.R.C. ¶ 61,228 at P 2 (2013).

168. *Id.* at 2 (citing 16 U.S.C. § 824a-3(h)(2)(B) (2012)).

169. Petition for Enforcement and Declaratory Order Pursuant to PURPA Section 210(h) at 1, 4, *Hydrodynamics Inc., Montana*, FERC Docket No. EL13-73-000 (Jun. 14, 2013) (citing *Southern Cal. Edison Co.*, 70 F.E.R.C. ¶ 61,215, at p. 61,677 (1995), on the need to permit QFs to participate in a non-discriminatory fashion, which Petitioners asserted requires all source solicitations be conducted).

170. Request for Leave to Answer and Answer of Hydrodynamics, Inc., Montana et al. at 48, *Hydrodynamics*, FERC Docket No. El13-73-000 (Aug. 8, 2013).

171. Petition, *supra* note 169, at 5 (alleging that these entities are acting in a discriminatory manner).

172. Motion to Intervene and Protest of the Edison Electric Institute, *Hydrodynamics*, FERC Docket No. EL13-73-000 (July 19, 2013); Motion to Intervene and Protest of the National Association of Regulatory Utility Commissioners, *Hydrodynamics*, FERC Docket No. EL13-73-000 (July 19, 2013). EEI did not intervene in any other 210(h) enforcement action in 2013.

173. The MPSC answered:

> Although this Commission disagreed with the Idaho PSC as to whether certain QFs were subject to the new rule, [the] FERC did not indicate in any such rulings that the Idaho PSC was violating PURPA by limiting the availability of the standard rate to certain types of over 100 kW QFs.

Answer and Motion to Dismiss of the MPSC to Petition for Declaratory Order and Petition for Enforcement Pursuant to PURPA Section 210(h) at 32, *Hydrodynamics*, FERC Docket No. EL13-73-000 (July 19, 2013)

The Petitioners' answer, filed August 8, 2013, challenged the intervenors' assertions that solicitations are being run fairly and that QFs are simply not competitive.[174] The Petitioners asserted that:

> QFs are being discriminated against in Montana by NorthWestern and the MPSC is plainly and unapologetically allowing it to take place. NorthWestern is not required to hold the competitive solicitations contemplated by the MPSC Rule at any established interval, and thus NorthWestern does not hold them. No QF has won a competitive solicitation in Montana, and NorthWestern has only held the competitive solicitation contemplated by the MPSC rule once since 2002. The only resources required to win competitive solicitations in order to sell their generation to NorthWestern are QFs.[175]

F. Solar Projects

We address a pair of solar project petitioners together as they are affiliate companies. The petitioners challenged feed-in tariff programs in Vermont and California on the grounds that the programs have been implemented in a manner inconsistent with PURPA and deny the petitioners the ability to receive full avoided cost rates from purchasing utilities.

1. Otter Creek Solar LLC

Otter Creek Solar LLC (Otter Creek) petitioned the Commission to institute a section 210(h) enforcement action against the Vermont Public Service Board (VPSB) and a series of orders it issued to create a feed-in tariff program implemented by VPSB called the Sustainability Priced Energy Enterprise Development Program (SPEED).[176] Otter Creek asserted that the SPEED program does not comply with PURPA in several respects: the offer rates are not based on a calculation of avoided costs, QFs are forced to contract with a third party rather than a utility, and a certain amount of new capacity is set aside for utility-owned projects.[177]

The Commission declined to initiate an enforcement action in its Notice of Intent Not to Act, issued June 27, 2013.[178] The Commission found that because the SPEED program is an optional program for certain small renewable QFs, and Vermont's existing Rule 4.100 complies with PURPA, Vermont met its burden of implementing a program consistent with PURPA.[179] The Commission stated that "[n]othing in the Commission's regulations limits the authority of either an electric utility or a QF to agree to rates for any purchases or terms or conditions

(citing *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 (2012); *Rainbow Ranch Wind, LLC*, 139 F.E.R.C. ¶ 61,077 (2012); *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011)).

174. Request for Leave to Answer and Answer, *supra* note 170, at 11-12. A revised answer was filed on August 9, 2013.

175. *Id.* at 57.

176. Petition for Enforcement Under PURPA at 1, *Otter Creek Solar LLC*, FERC Docket No. EL-13-000 (May 1, 2013).

177. *Id.* at 1-2.

178. *Otter Creek Solar LLC*, 143 F.E.R.C. ¶ 61,282 at P 2 (2013).

179. *Id.* at P 4.

relating to any purchases which differ from the rates or terms or conditions which would otherwise be required by the Commission's regulations."[180]

Otter Creek filed a request for reconsideration and/or clarification on July 24, 2013.[181] Otter Creek sought clarification from the Commission as to whether (1) the SPEED program's fixed mandatory pricing scheme is a voluntary or a mandatory program and (2) whether the Commission's holding permits a state to create two sets of avoided cost rates for a single QF under two separate programs.[182] Otter Creek asserts that the Commission's holding in this matter reverses the Commission's ruling in *California Public Utilities Commission*[183] "that a [s]tate cannot mandate a price in excess of avoided costs or that have not been determined to be avoided costs."[184] It further notes that a program may be voluntary from a generator's standpoint, but not from a utility's standpoint, which Otter Creek points out is what the Commission decided in the *California Public Utilities Commission*.[185]

The Commission granted Otter Creek's request for reconsideration on August 22, 2013, and the matter remains pending.[186]

2. Winding Creek Solar LLC

Winding Creek Solar LLC (Winding Creek), an affiliate of Otter Creek Solar LLC, filed a petition for enforcement pursuant to section 210(h)(2)(B) of PURPA requesting the Commission institute an enforcement action against the California Public Utilities Commission (CPUC) on the basis that the CPUC's implementation of a feed-in tariff program does not comply with PURPA and the Commission's regulations.[187] Winding Creek asserted that PURPA and the Commission's regulations require that QFs be able to receive long-term, full avoided cost rates, calculated at a purchasing utility's highest marginal cost, and that the CPUC's program deprived Winding Creek of this right.[188]

The Commission declined to act on this enforcement petition, leaving Winding Creek to pursue its remedies in state court.[189]

180. *Id.*

181. Request for Reconsideration and/or Clarification of Otter Creek Solar LLC, *Otter Creek*, FERC Docket No. EL13-60-000 (July 24, 2013).

182. *Id.* at 1.

183. *Id.* at 2; *see generally California Pub. Utils. Comm'n*, 132 F.E.R.C. ¶ 61,047 (2010).

184. Request for Reconsideration and/or Clarification, *supra* note 181, at 2.

185. *Id.* at 3.

186. *Otter Creek Solar, LLC*, FERC Docket No. EL13-60-001 (Aug. 22, 2013) (order granting rehearing).

187. Petition for Enforcement Under PURPA at 1, *Winding Creek Solar, LLC*, FERC Docket No. EL13-71-000 (June 13, 2013).

188. *Id.* at 1-3.

189. *Winding Creek Solar LLC*, 144 F.E.R.C. ¶ 61,122 at P 2 (2013).

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