REPORT OF THE FINANCE & TRANSACTIONS COMMITTEE

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I. UPDATE ON FEDERAL POWER ACT SECTIONS 203 AND 205

A. Public Service Company of Colorado

On December 18, 2014, the Federal Energy Regulatory Commission (FERC or Commission) issued an order granting a petition for a declaratory order filed by Public Service Company of Colorado (PSCO) that requested three Commission findings related to condemnation proceedings initiated by the City of Boulder (Boulder) in Colorado district court against PSCO's electric system in the Boulder area.[1] PSCO asked the Commission to find: (1) that Boulder's acquisition of certain facilities involved in the condemnation proceedings "require[d] prior Commission approval under section 203 of the Federal Power Act (FPA);" (2) that the Commission will apply its longstanding public interest criteria (the effect of the proposed transfer on competition, rates, regulation, and other relevant factors)

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1. *Colorado Pub. Serv. Co.*, 149 F.E.R.C. ¶ 61,228 at P 1 (2014).

in such a section 203 review; and (3) that "the Commission's exercise of its section 203 jurisdiction does not diminish the authority of the Colorado Public Utilities Commission (Colorado Commission) over the transfer of facilities that are the subject [of the condemnation proceedings]."[2] In granting PSCO's petition and issuing the declaratory order, the Commission stated that it was appropriate for the Commission to "terminate this controversy and thus remove uncertainty."[3]

PSCO's electric system in Boulder includes a 115 kilovolt (kV) transmission loop and associated transmission substations (Transmission Loop).[4] As part of a plan to establish a municipal electric utility, Boulder initiated condemnation proceedings in state district court in order to acquire the Transmission Loop.[5] PSCO asserted that a declaratory order from the Commission was necessary because the Colorado courts needed clarification on the Commission's section 203 jurisdiction generally (including whether it diminished the Colorado Commission's authority), the Commission's authority regarding rate impacts, as well as the need to address potential reliability issues in a section 203 proceeding.[6]

Citing the language of section 203(a)(1) of the FPA, PSCO argued that Commission jurisdiction applies to the condemnation of the Transmission Loop because PSCO "is a public utility, the Transmission Loop consists of jurisdictional facilities with a fair market value in excess of $10 million, and [PSCO] would be disposing, albeit involuntarily, of these facilities through a condemnation."[7]

Boulder opposed the proposed declaratory order.[8] Boulder contended that granting PSCO's petition would be contrary to the language of section 203 and a needless review of a fabricated controversy that depended on disputed, hypothetical scenarios.[9] Boulder contended that because it is a political subdivision of a state, and therefore not a public utility, FPA section 201(f) exempts it from section 203 requirements.[10] Boulder further argued that a taking of facilities by condemnation does not amount to a "disposition" of facilities that would trigger section 203.[11] In either case, according to Boulder, any Commission jurisdiction that would cause the Commission to exercise its authority is not implicated by the condemnation of the Transmission Loop.[12] Boulder also asserted that no present controversy exists regarding section 203 and its criteria for Commission approval because there is no section 203 application presently

2. *Id.*

3. *Id.* at P 29.

4. *Id.* at P 2.

5. 149 F.E.R.C. ¶ 61,228 at PP 2-3.

6. *Id.* at P 8.

7. *Id.* at P 7 (citing 16 U.S.C. § 824b(a)(1) (2012) ("No public utility shall, without first having secured an order of the Commission authorizing it to do so—(A) sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of $10,000,000.")).

8. *Id.* at P 12.

9. *Id.* at P 13.

10. 149 F.E.R.C. ¶ 61,228 at P 14; 16 U.S.C § 824(f) ("No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State. . . .").

11. *Id.* at P 15.

12. *Id.*

before the Commission; therefore, the Commission should deny PSCO's petition.[13]

PSCO answered that "Congress' intent [with section 203] was to ensure that the Commission maintain oversight of *any transfer* of jurisdictional utility property," and noted that courts have held that a condemnation is a "sale" of assets, which clearly implicates the taking of the transmission loop as a disposition for section 203 purposes.[14]

The FERC agreed with PSCO and granted the petition for a declaratory order, noting that the pleadings in the proceeding evidenced a controversy and that it was addressing only the legal issues upon which PSCO sought declaratory relief and not making any public interest findings for purposes of section 203.[15] The Commission determined that a transfer by condemnation does trigger section 203 because "Congress' intent was to ensure that the Commission maintain oversight of *any transfer* of jurisdictional utility property," and that the legislative history "indicates that the focus of section 203 is on the disposition of control of jurisdictional facilities, however such disposition might be effected."[16] Such a reading of "dispose" in section 203 is essential, the Commission reasoned, because otherwise "certain types of power sales facilities and corporate transactions could escape Commission oversight," a result Congress clearly intended to avoid.[17] If voluntary transfers of jurisdictional facilities to non-jurisdictional entities require Commission approval, then "there is no basis for finding that the involuntary nature of a transfer distinguishes it from this precedent and permits a jurisdictional void."[18]

The Commission also confirmed that it would apply its public interest criteria in a section 203 review of the disposition of the Transmission Loop.[19] The Commission ruled that it would apply "both its traditional criteria [effect of the proposed transfer on competition, rates, and regulation] as well as any other factors it deems necessary to the determination of whether the proposed transaction is consistent with the public interest."[20] Finally, the Commission affirmed that the "exercise of its authority under section 203 with regard to a transfer of the Transmission Loop would not diminish the authority of the Colorado Commission to regulate the transfer of any facilities that are subject to its jurisdiction," noting that "[t]his principle is well-established and supported by precedent."[21]

13. *Id.* at P 16.

14. *Id.* at PP 20-21 (quoting *Cent. Illinois Pub. Serv. Co.*, 42 F.E.R.C. ¶ 61,073, at p. 61,328 (1988) (emphasis in original)).

15. 149 F.E.R.C. ¶ 61,228 at P 31.

16. *Id.* at P 33 (quoting *Cent. Illinois Pub. Serv. Co.*, 42 F.E.R.C. ¶ 61,073, at p. 61,328 (emphasis in original); *Enova Corp. & Pac. Enters.*, 79 F.E.R.C. ¶ 61,107, at p. 61,490 (1997)).

17. *Id.* at P 34 (citing *Enova Corp. & Pac. Enters.*, 79 F.E.R.C. ¶ 61,107, at p. 61,489 (quoting S. Rep. No. 621, 74th Cong., 1st Sess. 50 (1935))).

18. *Id.*

19. *Id.* at P 36.

20. 149 F.E.R.C. ¶ 61,228 at P 36.

21. *Id.* at P 37.

B. Exelon Corporation and Pepco Holdings Merger

On November 20, 2014, the Commission approved a proposed merger and disposition of assets by which Exelon Corporation would acquire Pepco Holdings, Inc.[22] The Commission reviewed the proposed transaction under its merger policy statement and authorized the transaction as consistent with the public interest, subject to certain clarifications.[23]

1. Effect on Competition—Horizontal

The Commission found that the proposed merger will not have an adverse effect on horizontal competition in the generation market, as Pepco owns or controls only 17 megawatts (MW) of generation in the relevant market (PJM) and only 0.02% of the total installed capacity in each of the relevant submarkets of PJM, respectively, the AP South submarket and the 5004/5005 submarket.[24] The PJM Market Monitor and certain intervenors raised competition issues based on factors other than the combination of the generating assets of the two utilities.

The PJM Market Monitor asserted in its comments that the substantial portfolio of demand response resources that would combine as a result of the transaction required further analysis.[25] The Commission, however, found that no additional analysis was required.[26] The Commission noted that applicants had already provided a simplified "2ab" Herfindahl-Hirschman Index (HHI) calculation of market concentration which included Pepco's demand response resources as a capacity product participating in the PJM Base Residual Auction.[27] The Commission found that the combination of the approximately 700 MW of demand response resources controlled by Pepco, with the approximately 26,000 MW already controlled by Exelon, constituted only a small increase in market concentration for the capacity product and, therefore, will not have an adverse effect on competition in the PJM capacity market.[28] The Commission also cited the applicants' showing that Pepco's demand response resources had only a limited ability to participate in the PJM energy market, based on evidence that Pepco has been called upon only twice since 2010 to reduce demand under PJM's emergency demand response program, and has made offers in PJM's economic demand response program during only a total of thirty-one hours since 2010.[29]

The PJM Market Monitor also raised a concern that the applicants' combined capacity market-based demand response resources could impact prices in the PJM energy market, because these demand response resources are subject to significantly higher offer caps than generation resources and are eligible to set energy market prices in periods when all asset owners are pivotal.[30] While the Commission recognized that the applicants' combined capacity market-based

22. *Exelon Corp.*, 149 F.E.R.C. ¶ 61,148 at P 1 (2014).
23. *Id.*
24. *Id.* at P 44.
25. *Id.* at P 45.
26. *Id.* at P 35.
27. *Id.* at PP 30 & n.24, 45.
28. 149 F.E.R.C. ¶ 61,148 at P 45.
29. *Id.*
30. *Id.* at PP 46-47.

demand response resources increases their market share, the Commission determined that this would not result in an adverse impact on prices in the PJM energy market.[31] As support for its conclusion, the Commission recited information demonstrating recent improvements to the dispatch and pricing of capacity market-based demand response resources in PJM, including the ability to dispatch demand response resources prior to, as well as during, emergency conditions, and dispatching demand response resources subject to consideration of the resource's strike price.[32] The Commission found that these changes will encourage competition among providers and enable PJM to promote more efficient dispatch and effective operations going forward.[33]

The PJM Market Monitor further claimed that the proposed merger raised horizontal market power issues in transmission, noting that "under Order No. 1000, the Commission has adopted a new policy of encouraging competition in development for transmission projects."[34] "Thus, the Commission should consider a merger's effect on competition in transmission as part of its horizontal competition analysis."[35] The Commission determined that the combination of Exelon and Pepco would "not materially lessen the pool of all developers" that may participate in the PJM regional transmission enhancement process.[36]

2. Effect on Competition—Vertical

Under the merger policy statement, "[i]n mergers combining electric generation assets with inputs to generating power (such as natural gas, transmission, or fuel), competition can be harmed if a merger increases the merged firm's ability or incentive to exercise vertical market power in wholesale electricity markets."[37] In this case, the Commission was "satisfied that the Proposed Merger will not give Applicants the ability to withhold natural gas transportation to disadvantage rival generation as a result of the Proposed Merger."[38] "[T]he only additional natural gas distribution utility entering the Exelon corporate family[,] [Delmarva, has] no generation facilities directly connected to [its] system."[39] The Commission determined, therefore, that the applicants will not be able to use a newly affiliated local distribution company to withhold inputs to generation, and even assuming that applicants could prevent bypass of their distribution facilities, the Delmarva "natural gas distribution service territories represent less than [1%] of the PJM footprint, which limits the possibility of restricting new natural gas generation entry into PJM."[40]

31. *Id.* at P 48.

32. *Id.* at PP 47-48.

33. 149 F.E.R.C. ¶ 61,148 at P 48.

34. *Id.* at P 34.

35. *Id.* (citing Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323, at PP 225-344 (2011), *order on reh'g*, Order No. 1000-A, 139 F.E.R.C. ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 F.E.R.C. ¶ 61,044 (2012)).

36. *Id.* at P 49.

37. *Id.* at P 76.

38. 149 F.E.R.C. ¶ 61,148 at P 77.

39. *Id.*

40. *Id.*

The Commission also found sufficient evidence that the applicants' control of contracted interstate pipeline capacity and natural gas storage capacity "is not large enough to adversely affect vertical competition."[41] Applicants' combined pipeline capacity in the PJM market "is approximately [6%] of the total pipeline capacity in the [PJM]," and 7-8% of the AP South and 5004/5005 submarkets of PJM.[42] Applicants' share of natural gas storage capacity in the PJM market is about 2.5%.[43]

The Commission also analyzed whether the merger would adversely affect vertical competition from the combination of generation and transmission.[44] Applicants have turned over operation of their transmission facilities to PJM, an independent Regional Transmission Organization (RTO), eliminating "their ability to favor dispatch of Exelon's generation."[45] The Commission affirmed that it relies "upon RTO membership to conclude that merger applicants will not have the ability to use their expanded transmission system to harm competition in the wholesale electric markets."[46] The Commission also cited to precedent that holds that the "combination of electric generation and transmission facilities will not give merger applicants an ability to exercise vertical market power where the transmission facilities will continue to be subject to a Commission-approved [open access transmission tariff (OATT)]."[47] The Market Monitor commented that, while PJM is responsible for the interconnection process, "transmission owners have the responsibility for performing interconnection studies for generation, which can create a conflict of interest if the transmission owner also owns competing generation."[48] The Commission found, however, that the Market Monitor had not presented evidence to support that concern, and noted the levels of oversight by PJM over the interconnection process pursuant to the PJM OATT.[49] The Commission found that "[a]s a result of these provisions, following the Proposed Merger, Applicants may not improperly delay a non-affiliated generator's interconnection without being detected and facing possible consequences."[50]

3. Effect on Rates

The Commission found that the proposed merger will not have an adverse effect on rates, based upon applicants' five-year "hold harmless" commitment and subject to certain clarifications.[51] The "hold harmless" commitment means that the applicants will not include any merger-related costs in their transmission revenue requirements, except to the extent they can demonstrate that merger-related savings are equal to or in excess of all of the merger-related costs so

41. *Id.* at P 78.
42. *Id.*
43. 149 F.E.R.C. ¶ 61,148 at P 78.
44. *Id.* at P 79.
45. *Id.*
46. *Id.* *See also Nat'l Grid*, 117 F.E.R.C. ¶ 61,080 at P 45 (2006).
47. 149 F.E.R.C. ¶ 61,148 at P 79. *See, e.g.*, *Silver Merger Sub*, 145 F.E.R.C. ¶ 61,261, at P 46 (2013).
48. 149 F.E.R.C. ¶ 61,148 at P 80.
49. *Id.*
50. *Id.*
51. *Id.* at P 105.

included.[52] The "hold harmless" commitment applies "to all merger-related costs, including costs related to consummating the proposed merger and transition costs (both capital and operating) incurred to achieve merger synergies, incurred prior to the consummation of the Proposed Merger or in the five years after merger consummation."[53]

The Commission also clarified that, "if Applicants seek to recover merger-related costs that are the subject of [the] hold harmless commitment, they must submit a *new* filing under FPA section 205, and a concurrent informational filing in [the docket established for the applicants' section 203 application], in order to do so."[54] The Commission stated that it "will not authorize the recovery of merger-related costs in an annual informational filing under existing formula rates. The Commission will notice [a] new section 205 filing for public comment," and

> [w]ill determine [] if there is adequate support to show that recovery of merger-related costs is consistent with the hold harmless commitment and [if] the resulting new rate is just and reasonable in light of all the other factors underlying the proposed new rate when Applicants seek to recover such costs pursuant to a new FPA section 205 filing.[55]

Specifically, the Commission stated that, "[i]n the FPA section 205 filing, applicants must: (1) specifically identify the merger-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by the savings produced by the merger and realized by jurisdictional customers. Applicants must show that the proposed rate is just and reasonable in addition to providing appropriate evidentiary support demonstrating that merger-related costs have been offset by merger-related savings in order to recover those merger-related costs and comply with their hold harmless commitment."[56] The applicants' "subsequent FPA section 205 filing [must contain] reasonable documentation and estimates of the costs avoided in order to recover the merger-related costs. In addition, those savings must be realized prior to, or concurrent with, any authorized recovery."[57] The Commission stated that "evidence of offsetting merger-related savings cannot be based on estimates or projections of future savings, but must be based on a demonstration of actual merger-related savings realized by jurisdictional customers, which . . . may not occur until well after the transaction closes."[58]

The Commission further clarified that the concurrent filing in the relevant "FPA section 203 docket is informational only, to provide notice to interested parties regarding applicants' intention to recover merger-related costs."[59] The Commission stated that it did "not expect to make any further findings under FPA section 203 for purposes of the hold harmless commitment in response to such an informational filing."[60]

52. *Id.* at PP 105-06.
53. 149 F.E.R.C. ¶ 61,148 at P 105.
54. *Id.*
55. *Id.* at P 106.
56. *Id.* at P 107.
57. *Id.*
58. *Id.*
59. 149 F.E.R.C. ¶ 61 at P 108.
60. *Id.*

In addition, the Commission specified that the "hold harmless commitment applies to any acquisition premiums in wholesale rates, and . . . that, to the extent they may attempt to recover an acquisition premium during the time period when the hold harmless commitment applies, a new FPA section 205 filing will be required."[61] "If Applicants seek recovery of any acquisition premium (or acquisition adjustment) associated with the Proposed Merger, they must [make a showing] in a subsequent proceeding under FPA section 205," separate from the showing required for the recovery of merger-related costs subject to a hold harmless commitment, "that the acquisition was 'prudent and provides measurable, demonstrable benefits to ratepayers,'" supported by reasonable documentation and estimates of both merger-related costs and savings.[62]

4. Cross-Subsidization

Section 203 (a)(4) of the FPA also "requires the Commission to find that the transaction 'will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless [it] determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.'"[63] The Commission determined that the applicants' regulated utility subsidiaries each "purchase capacity and electricity [] to serve default load under independently-controlled auctions supervised by their retail regulators."[64] "These procedures prevent the Applicants from using [Pepco's] regulated utilities as secure purchasers for [Exelon's] merchant generation facilities or otherwise entering into contracts between affiliates at preferential rates."[65]

Ring-fencing is considered as a safe harbor for meeting the cross-subsidization demonstration "if a state commission adopts or has in place ring-fencing measures to protect customers against inappropriate cross-subsidization."[66] Applicants' proposed ring-fencing measures for the Pepco utilities were being reviewed by the relevant state commissions at the time of the Commission's order.[67] The Commission conditioned approval on applicants submitting an informational filing "within 10 days of each relevant state commission approval of Applicants' proposed ring-fencing provisions."[68]

5. Environmental Risks

Several intervenors contended that the Commission should evaluate certain environmental risks and analyze the proposed merger under the National

61. 149 F.E.R.C. ¶ 61,148 at P 111.

62. *Id.* at P 111 (citing *Silver Merger Sub, Inc.*, 145 F.E.R.C. ¶ 61,261 at P 68 & n.132 (2013); *ITC Holdings Corp.*, 139 F.E.R.C. ¶ 61,112 at P 50 & n.116 (2012)).

63. 149 F.E.R.C. ¶ 61,148 at P 29.

64. *Id.* at P 132.

65. *Id.* at P 134.

66. *Id*. at P 135 (citing *Supplemental Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,253 at PP 18, 24 (2007), 72 Fed. Reg. 42,277 (2007) (to be codified at 18 C.F.R. pt. 33)).

67. *Id.*

68. 149 F.E.R.C. ¶ 61,148 at P 135 (citing *Supplemental Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,253 at P 26).

Environmental Policy Act of 1969 (NEPA).[69] The Commission determined that the intervenors had not shown the issues they raised were relevant to the factors that the Commission considers in evaluating applications under FPA section 203 or that they were specifically related to the proposed merger.[70] "Under the Commission's regulations, approval of actions under FPA section 203 is categorically excluded from analysis under NEPA."[71] The regulations permit the Commission to determine that an action under FPA section 203 does not qualify for the categorical exclusion and require an environmental assessment or other environmental information, but only requires an assessment where circumstances indicate that an action may be a major Federal action significantly affecting the quality of the human environment.[72]

C. PPL Corporation and RJS Power Holdings

On December 18, 2014, under section 203(a)(1)(A) of the FPA, the Commission conditionally authorized a multi-step transaction pursuant to which the interests in indirect, wholly-owned power marketing and electric generation subsidiaries of PPL Corporation (collectively, the PPL Energy Supply Companies) would be separated from PPL Corporation, distributed to PPL Corporation shareowners, and combined with public utility subsidiaries of RJS Power Holdings, a wholly-owned indirect subsidiary of Riverstone, under Talen Energy Corporation, a new stand-alone, publicly traded independent power producer.[73] PPL Corporation's traditional public utility subsidiaries (PPL Electric, Louisville Gas & Electric, and Kentucky Utilities) would remain wholly-owned subsidiaries of PPL Corporation.[74] The Commission reviewed the proposed transaction under its merger policy statement and conditionally authorized the transaction as consistent with the public interest.[75]

The application presented a delivered price test for the PJM market as a whole and for PJM submarkets where the applicants' respective generation resources overlapped prior to the transaction.[76] Applicants acknowledged that the transaction triggered failures under the Commission's competitive screen analysis in the 5004/5005 submarket of PJM, one of the submarkets with the greatest

69. *Id.* at P 137.

70. *Id.* at P 140.

71. *Id.* at P 141 (citing 18 C.F.R. § 380.4(a)(16) (2014)). *See also Merger Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, at p. 31,128 (1996), 61 Fed. Reg. 68,595 (1996) (to be codified at 18 C.F.R. pt. 2); *Duke Energy Corp.*, 113 F.E.R.C. ¶ 61,297 (2005), *order on reh'g*, 118 F.E.R.C. ¶ 61,077 at P 35 & n.58 (2007) (noting the Commission typically does not consider environmental impacts in sections 203 and 205 of the FPA proceedings because such actions are categorically excluded from NEPA analysis); *Cal. Indep. Sys. Operator Corp.*, 93 F.E.R.C. ¶ 61,001, at p. 61,003 (2000); *cf.* Town of Norwood v. FERC, 202 F.3d 392, 406-07 (1st Cir. 2000).

72. 149 F.E.R.C. ¶ 61,148 at P 141 (citing 18 C.F.R. § 380.4(b)). *See also Town of Norwood*, 202 F.3d at 407.

73. *PPL Corp.*, 149 F.E.R.C. ¶ 61,260 at PP 1, 21 (2014).

74. *Id.* at PP 5-7, 126.

75. *Id.* at P 1; *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), 61 Fed. Reg. 68,595 (1996) (to be codified at 18 C.F.R. pt. 2), *reconsideration denied*, Order No. 592-A, 79 F.E.R.C. ¶ 61,321 (1997) (Merger Policy Statement).

76. 149 F.E.R.C. ¶ 61,260 at PP 49, 69, 81.

overlap of generation resources.[77] Accordingly, the application presented a proposed market power mitigation plan.[78] The Commission, however, determined that the proposed mitigation was insufficient to support a finding that the transaction would not have an adverse effect on competition.[79] The Commission authorized the transaction subject to conditions that included certain additional mitigation measures.[80]

In reviewing the applicants' delivered price test, the Commission noted that, "in states with retail competition where utilities retain provider of last resort obligations, . . . both Available Economic Capacity and Economic Capacity can provide useful information for analyzing the effect of the proposed transaction on competition."[81] Because PPL Corporation subsidiary PPL Electric has provider of last resort obligations, the Commission considered "both the results of the Economic Capacity and Available Economic Capacity analysis as relevant to the Proposed Transaction."[82]

The delivered price test analysis for Economic Capacity in the 5004/5005 PJM submarket showed "post-transactional HHI changes that exceed[ed] the 100-point threshold in a moderately concentrated market for Economic Capacity."[83] To address the screen failures in this submarket, applicants presented a mitigation plan based upon generation divestiture.[84] Specifically, applicants proposed that, within one year of the closing of the Proposed Transaction, "Talen Energy will enter into a contract or contracts for the divestiture of approximately 1,300 MW of generation under either of two alternative divestiture options."[85] Under Option 1, Talen Energy would divest "six Riverstone plants and one PPL plant in New Jersey and Pennsylvania."[86] Under Option 2, Talen Energy would divest "the same six Riverstone plants, plus a 399 MW coal-fired plant in Maryland and two PPL hydroelectric plants in Pennsylvania."[87] In addition, no company owning "more than 10[%] of PJM's summer installed capacity would be permitted to bid for the plants."[88] Finally, under an interim mitigation plan to be effective during the year in which the divestitures are being completed, an Independent Energy Manager will bid and dispatch all of the plants (under both Option 1 and Option 2).[89]

77. *Id.* at P 42.

78. *Id.* at P 43.

79. *Id.* at P 81.

80. *Id.*

81. 149 F.E.R.C. ¶ 61,260 at P 83 (citing *National Grid, PLC*, 117 F.E.R.C. ¶ 61,080 at P 26 (2006) (finding that "because New York State has retail competition but utilities retain significant [provider of last resort] obligations, both Available Economic Capacity and Economic Capacity can provide useful information in analyzing the effect of the merger on competition.")).

82. *Id.* (citing *Order Reaffirming Commission Policy*, 138 F.E.R.C. ¶ 61,109 at P 46 (2012)).

83. *Id.* at P 87.

84. *Id.*

85. *Id.* at P 88.

86. 149 F.E.R.C. ¶ 61,260 at P 88.

87. *Id.*

88. *Id.*

89. *Id.*

The Commission determined that "neither the Option 1 nor Option 2 divestiture proposals fully mitigate[d] the indicative screen failures in the summer super peak 1 period in the 5004/5005 submarket, [either] under [a] base case scenario or [a] sensitivity analysis."[90] "While the Commission has looked beyond screen failures in transactions where those screen failures are non-systemic and occur in off-peak hours," the screen failures here occur during a peak period where "limited alternative supply (due to binding transmission constraints) [] may be available to prevent an attempt to withhold production or to place uncompetitive bids in the market to drive up prices."[91] Where screen failures occur only in peak periods, the Commission has previously found that the transaction may have an adverse effect on competition, absent mitigation.[92]

Accordingly, the Commission specified, as additional mitigation for adverse effects on competition resulting from the transaction, that the transaction be conditioned either on: (1) limiting offers from the assets listed in either Option 1 or 2 that Talen Energy continues to own (after completing the chosen divestiture alternative) to cost-based offers in the energy market within the 5004/5005 submarket; or (2) divestiture of all of the assets listed in Options 1 and 2.[93] In either of these cases, the Commission said, "the Proposed Transaction will have no adverse effect on horizontal market power."[94] The Commission also accepted the applicants' commitment to exclude entities that own more than 10% of the total summer-rated installed capacity in the 5004/5005 PJM submarket from purchasing the bundled assets in the divestiture.[95] Market participants with more than 3% of the installed capacity in the broader PJM market, in the PJM MAAC submarket, or in the 5004/5005 submarket, would not be precluded from participating, and market power issues could be addressed in the proceedings to review the acquisitions under section 203.[96] The Commission also approved the applicants' proposed interim mitigation, directing that an independent monitor be appointed "to certify that Talen Energy has complied with the interim mitigation requirements."[97]

Because Talen Energy was not an applicant in this proceeding, the Commission imposed the following additional condition on its approval to ensure that these mitigation measures are properly implemented. Prior to closing, the applicants are required to file with the Commission a statement in which Talen Energy acknowledges and agrees to be bound by the terms of the mitigation

90. *Id.* at P 90.

91. 149 F.E.R.C. ¶ 61,260 at P 90 (citing *FirstEnergy Corp.*, 133 F.E.R.C. ¶ 61,222 at P 49 (2010) (finding no adverse effect on competition in PJM where screen failures occur in three off-peak periods); *Exelon Corp.*, 138 F.E.R.C. ¶ 61,167 at P 98 (2012) (finding no adverse effect on competition in PJM East where screen failures occur in three off-peak periods)).

92. *Id.* (citing *Oklahoma Gas & Electric Co*., 124 F.E.R.C. ¶ 61,239 at PP 43-47 (2008) (finding mitigation required for transaction resulting in two horizontal market power screen failures during summer peak in the Oklahoma Gas and Electric balancing authority area market)).

93. *Id.* at P 91.

94. *Id.*

95. *Id.* at P 92.

96. 149 F.E.R.C. ¶ 61,260 at P 92.

97. *Id.* at P 93.

accepted in this order, including the additional mitigation measures required to address market power concerns in the 5004/5005 submarket.[98]

In accordance with the Merger Policy Statement, the Commission also considered whether the proposed transaction would have an adverse effect on rates.[99] Referring to its November 2014 order authorizing the proposed merger of Exelon Corporation and Pepco Holdings, Inc., the Commission accepted PPL's "hold harmless" commitment, subject to the same clarifications set forth in the Exelon/Pepco order concerning the procedures the applicants must follow if they seek to recover any merger-related costs, the specific information that must be contained in any filing under section 205 to recover merger-related costs, and the requirement to make an informational filing in the section 203 docket in which the Commission authorized the parties' transaction.[100]

D. Nevada Power Company

On October 29, 2014, the Commission conditionally authorized Nevada Power to acquire a 50 MW operating natural gas-fired combined cycle electric generation plant and a 224 MW operating natural gas-fired combined cycle electric generation plant.[101] The Commission analyzed the proposed transaction in accordance with its merger policy statement and authorized it as being in the public interest subject to certain conditions.[102]

The Commission determined that the applicant's delivered price test analysis of horizontal market power was deficient.[103] Nevertheless, the Commission authorized the applicant to acquire the additional generating capacity based on an analysis of the company's *ability* and *incentive* to withhold output in order to drive up the market price.[104] Considering the "unique circumstances" presented, the Commission determined that, with appropriate mitigation, Nevada Power would not have the ability and incentive to withhold output in order to drive up the market price.[105] First, Nevada Power is required to fully credit any profits from wholesale sales to retail customers through a fuel adjustment clause, which the Commission previously found in *Nevada Power Co.* reduces the incentive for Nevada Power to raise prices because it will not receive any benefit from the additional revenue received from manipulating market prices.[106] Second, the applicant's parent, NV Energy, is already a significant net buyer of energy; the Commission cited information in the record showing that NV Energy derived 30 to 50% of its energy from purchased power in the two year period prior to the proposed transaction.[107] This reliance on purchased power demonstrated to the Commission that the

98. *Id.* at P 81.

99. *Id.* at P 119.

100. *Id.* at PP 122-24, Ordering Paragraph K.

101. *Nevada Power Co.*, 149 F.E.R.C. ¶ 61,079 at PP 1-2 (2014).

102. *Id.* at P 2.

103. *Id.* at P 33.

104. *Id.* at PP 33-35 (referencing *Supplemental Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,253 at P 60; Order No. 642, F.E.R.C. STATS. & REGS. ¶ 31,111 at p. 31,897 (2000), 65 Fed. Reg. 70,983 (2000) (to be codified at 18 C.F.R. pt. 33); *Duke Energy Corp.*, 136 F.E.R.C. ¶ 61,245 at P 126 (2011)).

105. *Id.* at P 35.

106. 149 F.E.R.C. ¶ 61,079 at P 33; *Nevada Power Co.*, 145 F.E.R.C. ¶ 61,022 at P 28.

107. 149 F.E.R.C. ¶ 61,079 at P 34.

applicant "lacks the incentive to induce higher market prices."[108] The effect of the transaction, the Commission determined, would increase NV Energy's reliance on purchased power.[109] In combination with a "state-mandated retirement of 300 MW of coal-fired capacity by the end of calendar year 2014, with relative lower dispatch costs," NV Energy's available economic capacity (i.e., the amount of capacity it has available to withhold) would decrease by roughly 30 MW.[110] Thus, the Commission found that "[i]n effect, the Proposed Transaction *decreases* any incentive that Nevada Power might now have to exercise horizontal market power."[111] Because the state-mandated coal plant retirement was critical to this analysis, the Commission conditioned its approval of the transaction on applicants' proposed interim mitigation, where it committed to sell any economic output of the newly acquired capacity off-system for the period between the closing of the proposed transaction and the retirement of these coal-fired units.[112]

II. UPDATE ON FEDERAL POWER ACT SECTION 204

Pursuant to section 204 of the Federal Power Act, requests by a "public utility" for authorization to issue securities or to assume obligations or liabilities in respect of any security shall be granted if the Commission finds that the issuance or assumption:

> (a) [I]s for some lawful object, within the corporate purposes of the applicant and compatible with the public interest, which is necessary or appropriate for or consistent with the proper performance by the applicant of service as a public utility and which will not impair its ability to perform that service[;] and (b) [I]s reasonably necessary or appropriate for such purposes.[113]

A. Alternative Bases for Finding that the Proposed Securities Issuance or Assumption of Obligations or Liabilities will not Impair the Ability to Perform Public Utility Service

In *Portland General*, the Commission found that the proposed issuance of securities would not impair the utility's ability to perform public utility service based on the applicant's demonstration that it had successfully accessed both debt and equity markets, and had access to state regulatory procedures to raise additional funds needed to ensure its ability to meet its customers' needs and cover its debt obligation.[114] In *South Carolina Generating Company, Inc.*, the generating company applicant passed through all of its costs, including debt service obligations, to an affiliate utility under a unit power sales agreement and Commission-approved formula rates, and its obligations to third party debt holders were guaranteed by its parent company.[115] Transmission-only public utilities

108. *Id.*
109. *Id.*
110. *Id.*
111. *Id.*
112. 149 F.E.R.C. ¶ 61,079 at P 35.
113. Federal Power Act, 16 U.S.C. § 824(c) (2012).
114. *Portland General Electric Co.*, 145 F.E.R.C. ¶ 61,063 at PP 16-17 (2014).
115. *South Carolina Generating Co.*, 149 F.E.R.C. ¶ 61,008 at PP 15-16. *See also AEP Appalachian Trans. Co.*, 147 F.E.R.C. ¶ 61,076 at P 21 (2014) (applicants' individual Commission-approved formula rate

received Commission orders granting issuances of securities on grounds that their Commission-accepted formula rates expressly permitted recovery of costs associated with the provision of transmission service, specifically including all costs associated with the requested issuances of debt securities.[116]

B. Generator Interconnection-Only Facilities: Blanket Authorizations under Section 204

In 2014, the Commission denied several requests by generator interconnection-only companies for blanket authorization under section 204 of the FPA and part 34 of the Commission's regulations.[117] In these orders, the Commission took the position that the blanket authorization under section 204 and part 34 is associated specifically with entities that own generation with the authority to sell electric power at market-based rates, and therefore should be included in applications for market-based rate authority under section 205 of the FPA.[118] The Commission cited language in Order No. 697 where the Commission stated that its practice is to grant blanket authorization under part 34 where the seller is not a franchised public utility providing electric service to customers under cost-based regulation *and has market-based rate authority*.[119] The Commission denied the blanket authorization to the generator interconnection-only company, as it had neither been granted market-based rate authority nor submitted an application for this authority.[120] Petitions for rehearing of two of these Commission decisions are pending.[121]

III. FEDERAL POWER ACT SECTION 305(A): POLICY STATEMENT ON PAYMENT OF DIVIDENDS FROM CAPITAL ACCOUNT

Section 305(a) of the FPA provides, in relevant part, that "[i]t shall be unlawful for any officer or director of any public utility . . . to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account."[122]

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mechanisms provide for the recovery of all relevant costs); *AEP Generating Co.*, 148 F.E.R.C. ¶ 61,143 at P 16 (2014) (costs of long-term debt covered by long-term power supply contracts).

116. *American Transmission Co. LLC*, 147 F.E.R.C. ¶ 61,180 at P 15 (2014); *ITC Great Plains, LLC*, 147 F.E.R.C. ¶ 61,005 at PP 11-12 (2014); *Northern Pass Transmission LLC*, 149 F.E.R.C. ¶ 61,012 at P 13 (2014) (Commission approved formula rate under transmission service agreement provides for recovery of all costs associated with investment in the transmission line and cash flows to meet debt service payments when due).

117. *See generally Spring Canyon Energy LLC*, 149 F.E.R.C. ¶ 61,106 at PP 1-2 (2014); *Energia Sierra Juarez U.S. Transmission, LLC*, 149 F.E.R.C. ¶ 61,052 at P 21 (2014); *Dominion Solar Gen-Tie, LLC*, 148 F.E.R.C. ¶ 61,167 at P 26 (2014), *reh'g pending*; *Maine GenLead, LLC*, 146 F.E.R.C. ¶ 61,223 at P 20 (2014), *reh'g pending*.

118. *See generally id.*

119. *Maine GenLead, LLC*, 146 F.E.R.C. ¶ 61,223 at P 20 (citing Order No. 697, 119 F.E.R.C. ¶ 61,295 at P 999).

120. *See generally supra* note 68.

121. *See generally* 148 F.E.R.C. ¶ 61,167; 146 F.E.R.C. ¶ 61,223.

122. 16 U.S.C. § 825d(a) (2012).

The Commission has stated that section 305(a) was enacted in order to stem the practice of "holding companies . . . paying out excessive dividends on the securities of their operating companies."[123]

On July 17, 2014, the Commission issued a policy statement to provide guidance that the FPA should be interpreted as "not prohibiting the payment of dividends from funds included in capital account by any public utility that has a market-based rate tariff on file with the Commission, does not have captive customers, and does not provide transmission or local distribution services."[124]

Initially, the policy statement arose out of a petition filed in May 2013, on behalf of public utility subsidiaries recently acquired in the Exelon/Constellation merger transaction that sold power at wholesale pursuant to market-based rate authorizations, did not have captive customers, and did not provide transmission or local distribution services.[125] The issue raised in the petition was that the concerns underlying section 305(a)–protecting the financial integrity of a public utility with obligations to provide service to captive customers–did not apply in the case of a public utility selling wholesale power at market based rates without captive customers.[126] The Commission adopted the policy statement in recognition that the "electric industry has evolved."[127]

IV. QUALIFYING FACILITIES UPDATE

In the Report of the Finance & Transactions Committee for 2014, the Committee reported on a pending petition for enforcement action pursuant to section 210(h) of the Public Utility Regulatory Policies Act of 1978 (PURPA) filed challenging Montana's competitive solicitation process for qualifying facilities (QFs).[128]

On March 20, 2014, the Commission declined to initiate an enforcement action, but issued a declaratory order finding that the Montana Public Service Commission (MPSC) Rule and a 50 MW installed capacity limit for wind QFs, which applies to the cumulative purchases of all wind QFs greater than 100 kilowatts (kW), but equal to or below 10 MW, are inconsistent with PURPA and the Commission's regulations under PURPA.[129]

Referring to its rules implementing PURPA, the Commission stated that the "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[130] Noting the *Grouse Creek* decision from 2013, where the Commission

123. *Citizens Utils. Co.*, 84 F.E.R.C. ¶ 61,158, at p. 61,865 (1998).

124. *Payment of Dividends from Funds Included in Capital Account*, 148 F.E.R.C. ¶ 61,020 at P 1 (2014) (Policy Statement).

125. *Id.* at P 8.

126. *Id.* at P 7.

127. *Id.* at P 25.

128. *Report of the Finance & Transactions Committee*, 35 ENERGY L.J. 1, 18 (2014).

129. *Hydrodynamics, Inc.*, 146 F.E.R.C. ¶ 61,193 at PP 2, 7, 36 (2014).

130. *Id.* at P 31 (referencing *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, F.E.R.C. STATS. & REGS. ¶ 30,128, at p. 30,880 (1980), 45 Fed. Reg. 12,214 (1980), 45 Fed. Reg. 24,126 (1980) (to be codified at 18 C.F.R. pt. 292), *order on reh'g*; Order No. 69-A, F.E.R.C. STATS. & REGS. ¶ 30,160 (1980), 45 Fed. Reg. 33,958 (1980) (to be codified at 18 C.F.R. pt.

had determined that the "Idaho Commission's requirement that a QF file a meritorious complaint to the Idaho Commission before obtaining a legally enforceable obligation 'would both unreasonably interfere with a QF's right to a legally enforceable obligation and also create practical disincentives to amicable contract formation,'" the Commission said that "requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where . . . such competitive solicitations are not regularly held."[131] Accordingly, the Commission found the MPSC Rule "inconsistent with PURPA and the Commission's regulations implementing PURPA to the extent that it offers the competitive solicitation process as the only means by which a QF greater than 10 MW can obtain long-term avoided cost rates."[132]

The Commission also found the "50 MW installed capacity limit applicable to purchases from wind QFs larger than 100 kW but equal to or below 10 MW is inconsistent" with PURPA's goal of promoting QF development and fails to implement the Commission's regulations requiring an electric utility to purchase any capacity made available from a QF, and at a rate that, at the QF's option, is equal to forecasted avoided cost.[133]

V. TRANSACTION COSTS OF DISTRIBUTED GENERATION

Electric customers considering installing facilities and systems that allow them to generate all or a portion of their own electricity needs (distributed generation, or DG) need to evaluate the costs and benefits associated with the transaction, including the impact on their charges for electricity. Developers of distributed generation and their equity investors and financial backers need to understand and evaluate the costs and risks as well as the benefits associated with their investment. One of the important areas of cost and risk related to DG is the state utility electric rate regime and the decisions and policies of state regulators.

Wisconsin is the latest state to address issues of how to fairly apportion costs to customers who elect DG. In December 2014, the Wisconsin Public Service Commission (Wisconsin PSC) finalized three rate case decisions affecting how customers with DG systems are charged for electricity.[134] The Wisconsin PSC found that a utility's fixed costs "are not being borne by DG customers," and, with the expected increase in DG in Wisconsin, it is important for ratepayers making

292), *aff'd in part & vacated in part sub nom*. Am. Elec. Power Serv. Corp. v. FERC, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom*. Am. Paper Inst. v. Am. Elec. Power Serv. Corp., 461 U.S. 402 (1983)).

131. *Id.* at P 32 (citing *Grouse Creek Wind Park, LLC*, 142 F.E.R.C. ¶ 61,187 at P 40 (2013)).

132. *Id.* at P 33.

133. *Id.* at PP 33-34.

134. *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, No. 6690-UR-123, 2014 Wisc. PUC LEXIS 462 (Dec. 18, 2014) [hereinafter *Application of WPSC*]; *Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates*, No. 3270-UR-120, 2014 Wisc. PUC LEXIS 467 (Dec. 23, 2014) [hereinafter *Application of MGE*]; *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Authority to Adjust Electric, Natural Gas, and Steam Rates*, No. 5-UR-107, 2014 Wisc. PUC LEXIS 476 (Dec. 23, 2014) [hereinafter *Joint Application of We Energies*].

decisions whether or not to invest in DG "to understand the real costs and benefits" of those systems.[135]

The Wisconsin PSC's decisions increased monthly fixed rate electricity charges, imposed a per kW charge for certain DG facilities, and reduced the rates received by DG homeowners who sell excess generation back onto the grid. The Wisconsin PSC noted the state's goal to promote "cost effective" renewable energy resources is not achieved through an electricity rate structure that artificially inflates the economic benefits of DG facilities.[136] Recognizing the emergence and increased interest in DG, the Wisconsin PSC agreed that fixed rates should be better aligned with the fixed costs of providing service, regardless of the amount of electricity used.[137] The Wisconsin PSC found that the previous rate structure for the three utilities signaled to the ratepayer that the economic benefits of conservation were higher than the actual benefits, due to the fixed rate being too low or the variable energy rate being too high.[138] This resulted, according to the Wisconsin PSC, in other ratepayers paying for the difference between the benefit the ratepayer receives and the benefit actually incurred by the utilities from that ratepayer's reduced electricity demand.[139]

The Wisconsin PSC specifically dealt with special rates or charges applied to DG ratepayers. Wisconsin Electric Power Company (WEPCO) proposed new charges for DG ratepayers and to require ratepayers taking service under the DG tariffs to own their DG systems, disallowing third party ownership.[140] The Wisconsin PSC accepted some of WEPCO's proposed changes to its DG tariffs, stating that it "moves WEPCO a step closer to more appropriately aligning costs and fairly compensating customers that generate a portion of their electricity needs without increasing costs to those who cannot or do not do so."[141] However, the Wisconsin PSC rejected WEPCO's request for a blanket prohibition on third-party owned DG, instead, stating that it is reasonable "to evaluate whether third-party owned DG systems comply with Wisconsin statutes and administrative code on a case-by-case basis."[142]

The Wisconsin PSC approved WEPCO's proposal for DG excess electricity generation buyback rates to use "[locational marginal pricing (LMP)] plus the avoided cost of transmission."[143] The Wisconsin PSC also approved DG demand

135. *Joint Application of We Energies*, 2014 Wisc. PUC LEXIS 476, at *122.

136. *See, e.g.*, *Application of MGE*, 2014 Wisc. PUC LEXIS 467, at *62-63:

> The law requires the Commission to prioritize the development of renewable energy resources that are 'cost effective.' *Wis. Stat. §§ 1.12(3)(b)* and *(4)*, and *Wis. Stat. § 196.025(1)(ar)*. Thus, the law specifically sets forth a state policy that the cost effectiveness be a significant consideration in the development of these resources. The law does not require the Commission to artificially inflate, to any degree, the cost effectiveness of renewable energy resources when it sets utility rates.

137. *Application of WPSC*, 2014 Wisc. PUC LEXIS 462, at *58-61; *Joint Application of We Energies*, 2014 Wisc. PUC LEXIS 476, at *82, *86.

138. *Application of WPSC*, 2014 Wisc. PUC LEXIS 462, at *62-63; *Application of MGE*, 2014 Wisc. PUC LEXIS 467, at *57; *Joint Application of We Energies*, 2014 Wisc. PUC LEXIS 476, at *87.

139. *Application of WPSC*, 2014 Wisc. PUC LEXIS 462, at *63; *Application of MGE*, 2014 Wisc. PUC LEXIS 467, at *57-58; *Joint Application of We Energies*, 2014 Wisc. PUC LEXIS 476, at *87.

140. *Joint Application of We Energies*, 2014 Wisc. PUC LEXIS 476, at *116-18.

141. *Id.* at *119-20.

142. *Id.* at *133.

143. *Id.* at *122-23.

charges "based on the name-plate capacity."[144] On January 22, 2015, the Alliance for Solar Choice, an industry group of solar rooftop companies, and Renew Wisconsin, a renewable energy advocacy group, filed an appeal of the Wisconsin PSC's WEPCO decision in state court to overturn the new fees imposed on DG.[145]

VI. LIQUEFIED NATURAL GAS (LNG) EXPORT AUTHORIZATIONS

A. DOE Order of Precedence

Effective August 15, 2014, the Department of Energy Office of Fossil Energy (DOE) revised its procedures for reviewing liquefied natural gas (LNG) export applications.[146] The revised procedures reverse, in part, DOE's long-held practice of issuing conditional decisions for export of natural gas before DOE completes its full review process.[147] DOE's regulations provide that DOE may issue a conditional order, at its discretion, during a proceeding prior to issuance of a final opinion and order.[148]

With increased demand for approval to export LNG from the lower forty-eight states, DOE issued a Notice of Proposed Procedures for Liquefied Natural Gas Export Decisions in an effort to streamline its resources to evaluate projects from the most viable applicants.[149] DOE also explained that it no longer appeared necessary for DOE to issue a conditional authorization for applicants and for the FERC to commit the substantial resources necessary to initiate the environmental review process.[150]

Under the revised procedures, DOE will use the following criteria to determine when to act on an export application:

> (1) For those projects requiring an [environmental impact statement (EIS)], 30 days after publication of a Final EIS, (2) for projects for which an [environmental assessment (EA)] has been prepared, upon publication by DOE of a Finding of No Significant Impact, or (3) upon a determination by DOE that an application is eligible for a categorical exclusion pursuant to DOE's regulations implementing NEPA.[151]

DOE confirmed in its final rule that the revised procedures would not affect the validity of the conditional orders issued by DOE prior to the August 15, 2014,

144. *Id.* at *125-26.

145. *See generally* Thomas Content, *Solar Companies, Advocates Go to Court to Stop We Energies Solar Fees*, J. SENTINEL (Jan. 23, 2015), http://www.jsonline.com/blogs/business/289516941.html.

146. Procedures for Liquefied Natural Gas Export Decisions, 79 Fed. Reg. 48,132, 48,135 (Aug. 15, 2014).

147. *Id.* at 48,133; *cf.* Proposed Rule, Import and Export of Natural Gas; New Administrative Procedure, 46 Fed. Reg. 44,696, 44,700 (Sept. 4, 1981) (codified at 10 C.F.R. pts. 205 and 590). Also, on December 5, 2012, DOE issued an Order of Precedence describing the order in which it would evaluate LNG export applications by grouping applicants as follows: (1) applicants that have received approval from the FERC to use the FERC Pre-Filing process on or before December 5, 2012; (2) applicants that have not initiated the NEPA review process, but that have applied to DOE for export authority; and (3) applicants that had not applied to DOE, as of December 5, 2012.

148. 10 C.F.R. § 590.402 (2015).

149. Notice of Proposed Procedures for Liquefied Natural Gas Export Decisions, 79 Fed. Reg. 32,261 (June 4, 2014).

150. *Id.* at 32,263.

151. *Id.*

effective date.[152] DOE would instead proceed by reconsidering the authorization when the NEPA review process for those projects is complete.[153]

B. DOE Change of Control Notice

Effective November 5, 2014, DOE revised procedures concerning an applicant's or authorization holder's obligation to notify DOE of any change in control.[154] Existing DOE regulations require that applicants and authorization holders must amend pending applications or request authorization for the transfer of control, as applicable.[155] However, DOE's revised procedures clarify the timing for applicants or authorization holders to file notice of changes in control, and the procedures applicants and authorization holders must follow to affect the change of control.[156]

For all applicants and authorization holders, the DOE's revised procedures provide that a notice of changes in control may be filed "before such changes have been effectuated," but in any case a notice of change of control must be filed "no later than 30 days after such changes have been effectuated."[157] For pending applications–e.g., proceedings in which DOE has not yet issued a final opinion and order–entities may notify DOE of changes in control by amending the pending application and serving the amendment in accordance with DOE regulations.[158] Although DOE will give immediate effect to the amendment, DOE will consider answers it receives within fifteen days of service of the notice in accordance with DOE regulations.[159] To the extent answers are filed and issues raised, DOE will address those issues in its final order on the pending application.[160]

For export authorizations already issued by DOE, authorization holders may submit a statement of change in control to DOE by completing one of the following: (1) emailing the filing change in control (CIC) and FE Docket number in the title line; (2) mailing an original and three paper copies of the filing to DOE; or (3) hand delivering an original and three paper copies of the filing to DOE.[161] DOE will give effect to the CIC upon receipt and then publish a notice of the change in the *Federal Register*.[162] Interested persons will have fifteen days from the date of publication in the *Federal Register* to submit motions to intervene, protest, and answer the statement of CIC.[163] If no answers are filed, and DOE does not act on its own; the change of control will be deemed granted thirty days

152. Procedures for Liquefied Natural Gas Export Decisions, 79 Fed. Reg. at 48,136.

153. *Id.*

154. Notice of Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas, 79 Fed. Reg. 65,541 (Nov. 5, 2014) (to be codified at 10 C.F.R. pt. 590).

155. 10 C.F.R. § 590.204(b) (2015); 10 C.F.R. § 590.405 (2015).

156. Notice of Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas, 79 Fed. Reg. at 65,542.

157. *Id.*

158. *Id.*

159. *Id.*; *see, e.g.*, 10 C.F.R. § 590.302(b) (2015).

160. Notice of Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas, 79 Fed. Reg. at 65,542.

161. *Id.*

162. *Id.*

163. *Id.*

after publication in the *Federal Register*.[164] To the extent answers are filed, DOE will issue a determination whether the proposed CIC alters the original determination that the export authorization was not "inconsistent with the public interest."[165]

Although DOE will give immediate effect to the amendment, DOE will consider answers it receives within fifteen days of service of the notice in accordance with DOE regulations.[166] To the extent answers are filed and issues raised, DOE will address those issues in its "final order on the pending application."[167]

164. *Id.*

165. Notice of Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas, 79 Fed. Reg. at 65,542.

166. *Id.*; *see, e.g.*, 10 C.F.R. § 590.302(b).

167. Notice of Procedures for Changes in Control Affecting Applications and Authorizations to Import or Export Natural Gas, 79 Fed. Reg. at 65,542.