REPORT OF THE STATE COMMISSION PRACTICE & REGULATION COMMITTEE

This report summarizes significant state legislative enactments, administrative decisions, and jurisprudence affecting the utility sector from June 2011 through August 2013.*

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I. MID-ATLANTIC

A. District of Columbia

1. Potomac Electric Power Company (PEPCO)

On September 27, 2012, the District of Columbia Public Service Commission (D.C. PSC) issued Order No. 16930 regarding PEPCO's July 8, 2011, application to increase its retail distribution rates in order to produce an additional $42.1 million in annual revenue.[1] The D.C. PSC approved a $24.4 million increase, or just over half of PEPCO's proposal.[2] Nearly one third of the approved increase was associated with costs of PEPCO's Advanced Metering Infrastructure program, which was mandated by the District of Columbia City Council.[3] The D.C. PSC established PEPCO's return on equity (ROE) at 10.0%, which was then reduced by fifty basis points to reflect the risk-reducing effect of PEPCO's decoupling mechanism.[4] Similar to the Maryland Public Service Commission's (Maryland PSC) decision in Case No. 9286, discussed *infra*, the D.C. PSC rejected PEPCO's proposed Reliability Improvement Recovery Mechanism.[5] The D.C. PSC also directed PEPCO to provide, in advance of its

1. Application of the Potomac Electric Power Company for Authority to Increase Its Rates, Order No. 16930, Case No. 1087 (D.C. P.S.C. Sept. 27, 2012). PEPCO's requested increase was subsequently reduced to $39.8 million to reject updated information. *Id.* ¶ 2.

2. *Id.* ¶ 539(j).

3. *Id.* at v, ¶ 518 (discussing D.C. CODE § 34-1562(c)-(d) (2010 Repl.)).

4. *Id.* ¶¶ 156, 177.

5. *Id.* ¶ 475.

next rate case application, detailed information about its distribution construction program.[6]

2. Washington Gas Light Company

On May 15, 2013, the D.C. PSC issued an order regarding its November 2, 2011, investigation into the reasonableness of Washington Gas Light Company's (WGL) base rates.[7] Via a February 29, 2012, filing in this proceeding, WGL sought to increase revenue by $29 million.[8] Ultimately, the D.C. PSC approved an $8.4 million increase.[9] The D.C. PSC established WGL's ROE at 9.25%.[10] Consistent with its adherence to traditional ratemaking principles as expressed in Order No. 16930, the D.C. PSC rejected WGL's proposal to recover the costs of certain infrastructure projects through a surcharge.[11]

B. Maryland

1. Potomac Electric Power Company

On December 21, 2011, the Maryland PSC issued an order in its proceeding investigating the overall reliability of PEPCO's distribution system and the quality of the electric service PEPCO provides to its customers.[12] The Maryland PSC's investigation commenced in response to "an unusually large number of customer complaints about chronic electric outages . . . , both during storms and during fair weather days."[13] The Maryland PSC found "that PEPCO failed to satisfy its legal obligation to provide its customers with reliable service"[14] and that "PEPCO's failure to maintain its system properly over a period of years subjected its customers to excessively high frequencies and long durations of electric outages, during storm events and on fair weather days, and PEPCO compounded those reliability problems through poor customer communication."[15] The Maryland PSC determined that PEPCO's low level of reliability was a direct result of its poor vegetation management practices.[16] The Maryland PSC assessed a $1 million monetary penalty against PEPCO.[17]

6. *Id*. ¶ 485.

7. Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service, Order No. 17132, Case No. 1093 (D.C. P.S.C. May 15, 2013).

8. *Id.* ¶ 1. WGL's requested increase was subsequently reduced to $28.4 million to reflect updated information. *Id.* ¶ 4.

9. *Id.* ¶ 340(n).

10. *Id.* ¶ 47.

11. *Id.* ¶ 269, 271.

12. Investigation into the Reliability and Quality of the Electric Distribution Service of Potomac Electric Power Company, Order No. 84564, Case No. 9240 (Md. P.S.C. Dec. 21, 2011).

13. *Id.* at 1.

14. *Id.* at 3.

15. *Id.* at 1.

16. *Id.* at 2.

17. *Id.* at 3, 50-62 (discussing penalty authority provided by MD. CODE ANN., PUB. UTIL. COS. § 13-201 (2012)). The Maryland PSC notes that, on May 10, 2011, Governor O'Malley signed into law House Bill 391, which increased the maximum fine from $10,000 per day per violation to $25,000 per day per violation. *Id.* at 51 n.160. However, the $1 million fine was based on the maximum of $10,000 per day per violation that was in effect at the time of the violations. *Id.*

In addition to assessing the $1 million monetary penalty, the Maryland PSC found that PEPCO's "2011 reliability expenditures were increased due to many years of imprudently inadequate expenditures and neglect."[18] Thus, the Maryland PSC put PEPCO on notice that, "[i]n the [c]ompany's next rate case, the Commission will review reliability spending in 2011-2012, and will disallow the amount that is larger due to the Company's imprudent management in earlier years."[19]

2. Potomac Electric Power Company

On July 20, 2012, the Maryland PSC issued an order in Case No. 9286 regarding PEPCO's December 16, 2011, application to increase its retail distribution rates in order to increase revenue by approximately $68 million.[20] Ultimately, the Maryland PSC approved an $18.1 million increase.[21] The Maryland PSC established PEPCO's ROE at 9.31%.[22] It also rejected PEPCO's proposal "to deviate, in the [c]ompany's favor, from our historic ratemaking precedents" in two key respects.[23] First, the Maryland PSC rejected PEPCO's proposed "Reliability Improvement Recovery Mechanism," which, as the name suggests, was a surcharge proposal purportedly designed to facilitate capital investments in reliability infrastructure.[24] Inter alia, the Maryland PSC found that "the reliability surcharge proposed will have very little to do with reliability."[25] Second, the Maryland PSC denied certain aspects of PEPCO's proposal to recover out-of-test-year operation and maintenance (O&M) expenses and plant additions.[26] Finally, following up on its admonition from its December 21, 2011, order in Case No. 9240,[27] the Maryland PSC disallowed $6.4 million in O&M expenses, which was the amount it determined to constitute "catch up" spending to cure "years of system neglect."[28]

18. *Id.* at 3.

19. *Id.* at 3-4, 60.

20. Application of Potomac Electric Power Company for Authority to Increase Its Rates and Charges for Electric Distribution Service, Order No. 85028, Case No. 9286 (Md. P.S.C. July 20, 2012).

21. *Id.* at 1-2.

22. *Id.* at 2, 4, 109.

23. *Id.* at 1.

24. *Id.* at 2, 143-47.

25. *Id.* at 143.

26. *Id.* at 2 ("deny[ing] all of PEPCO's requests for recovery outside of the test period except for in-service capital expenditures relating directly to reliability and estimated costs to implement the Commission's contact voltage regulations"); *see also id.* at 35 (not allowing recovery of expenses relating to Rulemaking 43, Maryland's Service Quality and Reliability Standards). The Maryland PSC did, however, allow recovery of certain out-of-test-year plant additions and O&M expenses. *Id.* at 17-18, 34-35.

27. Order No. 84564, *supra* note 12, at 3-4 (putting PEPCO on notice that it will disallow the amount of reliability spending that is larger due to past imprudent management).

28. Order No. 85028, *supra* note 20, at 2-3, 38-39. In addition, the Maryland PSC disallowed $1.5 million in outside counsel and witness fees that PEPCO sought to recover with respect to Case No. 9240. *Id.* at 2.

C. Pennsylvania

1. Distribution System Improvements

On February 14, 2012, Governor Tom Corbett signed into law Act 11 of 2012 to allow natural gas distribution companies and electric distribution companies to petition the Pennsylvania Public Utility Commission (PA PUC) for approval to implement a Distribution System Improvement Charge (DSIC) to provide for "the timely recovery of the reasonable and prudent costs incurred to repair, improve[,] or replace eligible property in order to ensure and maintain adequate, efficient, safe, reliable[,] and reasonable service."[29] On August 2, 2012, the PA PUC issued a final implementation order for the DSIC program.[30]

2. Act 129 (Energy Conservation)

Under Act 129 of 2008, the PA PUC was tasked with developing an energy efficiency and conservation (EE&C) program for electric distribution companies (EDCs) with at least 100,000 customers.[31] The EE&C was to reduce electric consumption by at least 1% by May 31, 2011.[32] In addition, EDCs were to reduce the total annual weather-normalized consumption by a minimum of 3% by May 31, 2013.[33] To address peak demand, EDCs were to reduce "by a minimum of [4.5%] of the EDC's annual system peak demand in the 100 hours of highest demand, measured against the EDC's peak demand during the period of June 1, 2007 through May 31, 2008."[34] Under Act 129, the PA PUC was further ordered to assess the cost-effectiveness of the EE&C program by November 30, 2013 (and every five years thereafter) and set additional incremental reductions in electric consumption if the program's benefits exceeded its costs.[35]

In March 2012, the PA PUC began the process of addressing the state of its EE&C program by issuing a letter soliciting comments on the future development and design of the program.[36] On August 2, 2013, the PA PUC issued an implementation order finding that, to date, the PA PUC-approved EE&C plans have provided cost-effective consumption reductions for the Phase I EE&C Program; therefore, the PA PUC required EDCs to adopt additional required incremental reductions in consumption for another EE&C Program term of five years.[37] The required reductions for Pennsylvania's seven EDCs range from 1.6% to 2.9% from 2009 to 2010 consumption levels during Phase II of the EE&C.[38]

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29. 66 PA. CONS. STAT. § 1353(a) (2013).
30. Implementation of Act 11 of 2012, Docket No. M-2012-2293611 (Pa. P.U.C., Aug. 2, 2012).
31. 66 PA. CONS. STAT. § 2806.1(a), (l) (2013).
32. *Id.* § 2806.1(c)(1).
33. *Id.* § 2806.1(c)(2).
34. *Id.* § 2806.1(d)(1).
35. *Id.* § 2806.1(c)(3).
36. Energy Efficiency and Conservation Program, Docket No. M-2012-2289411, at 7 (Pa. P.U.C. Aug. 2, 2012).
37. *Id.* at 10-13.
38. *Id.* at 24.

II. SOUTHERN REGION

A. Florida

1. Major Rate Cases

a. Gulf Power Company (Gulf)

In July 2011, Gulf, serving Florida's panhandle, filed with the Florida Public Service Commission (FPSC) for a rate increase of $101.6 million and a $4.02 million step increase in January 2013 for its Crist Units 6 & 7 turbine upgrade projects (Crist Projects) through the Environmental Cost Recovery Charge on its customers' bills.[39] The proposed rate increase was based on an 11.7% ROE.[40] In an April 2012 order, the FPSC approved a revenue increase of $64.1 million and a step increase of $4.02 million for Gulf, based on a 10.25% ROE, effective January 1, 2013.[41] However, the FPSC allowed Gulf to recover the Crist Projects costs through rate base.[42] In addition, the FPSC reduced Gulf's annual storm damage accrual from $6.8 million to $3.5 million and reduced Gulf's executive stock and incentive compensation from $12.6 million to $8.7 million.[43] The FPSC also denied Gulf's request of $26.8 million in acquisition and evaluation costs for its North Escambia site to be included in the base rate, finding that the need for the project had not yet been determined by the Commission.[44] In August 2012, the FPSC issued an order denying Gulf's motion for reconsideration of the decision to exclude the North Escambia site costs from its rates.[45]

b. Progress Energy Florida (PEF)

PEF, Florida's second largest electric utility, was operating under a settlement agreement since June 2010 that included a base rate freeze through December 2012 so long as PEF's ROE remained between 9.5% and 11.5%.[46] In January 2012, PEF filed a petition for limited proceedings to resolve outstanding issues in several nuclear cost recovery dockets, including FPSC's investigation of Crystal River Unit 3 nuclear facility's (CR3) extended outage, replacement fuel, and projected repair costs.[47] Routine maintenance and upgrades in 2009

39. Petition for Increase in Rates by Gulf Power Company at 2-3, Order No. PSC-12-0179-FOF-EI, Docket No. 110138-EI (Fla. P.S.C. Apr. 3, 2012) (final order).

40. Petition at 1, Petition for Increase in Rates by Gulf Power Company at 1, Docket No. 110138-EI (Fla. P.S.C. July 8, 2011).

41. Petition for Increase in Rates by Gulf Power Company, Order No. PSC-12-0179-FOF-EI, Docket No. 110138-EI, at 3, 33 (Fla. P.S.C. Apr. 3, 2012) (final order).

42. *Id.* at 3.

43. *Id.* at 85, 99.

44. *Id.* at 26.

45. Petition for Increase in Rates by Gulf Power Company, Order No. PSC-12-0400-FOF-EI, Docket No. 110138-EI, at 13 (Fla. P.S.C. Aug. 3, 2012).

46. Petition for Increase in Rates by Progress Energy Florida Inc., Order No. PSC-10-0398-S-EI, Docket No. 090079-EI, at 3, 5 (Fla. P.S.C. June 18, 2010).

47. Petition for Limited Proceeding to Approve Stipulation and Settlement Agreement by Progress Energy Florida, Inc., Order No. PSC-12-0049-PCO-EI, Docket No. 120022-EI, at 1 (Fla. P.S.C. Feb. 3, 2012).

cracked CR3's forty-two inch thick concrete container surrounding the nuclear reactor.[48] In March 2012, the FPSC issued an order approving a settlement agreement that provided $288 million in customer refunds for replacement power costs associated with the CR3 outage, and removal of CR3 from base rates while PEF decides what to do with the facility.[49] The settlement also limited customer costs for PEF's proposed Levy County nuclear plant through 2017 and provided for a base rate increase of $150 million in January 2013.[50]

c. Florida Power & Light Company (FPL)

FPL, the state's largest electric utility, was operating under a settlement agreement since February 2011 that included a base rate freeze.[51] In March 2012, FPL petitioned the FPSC for a $516.5 million base rate increase and a $173.9 million step increase to begin paying for a new, high-efficiency natural gas power plant in 2012.[52] The proposed rate increase was based on an 11.5% ROE plus a 0.25% performance "adder."[53] In January 2013, the FPSC issued an order approving a new FPL settlement for a base rate increase of $350 million and a 10.5% ROE.[54] FPL will receive step increases totaling $615 million as power plant modernizations come online.[55]

2. Major Litigation

The FPSC was a defendant in a lawsuit over its application of the so-called "advance fee," a 2006 law which allows utilities to collect costs for proposed nuclear plants before they are operational in an attempt to diversify Florida's fuel mix by making nuclear facilities a more attractive investment.[56] In suing to overturn the advance fee, Southern Alliance for Clean Energy argued that the Florida legislature unconstitutionally delegated authority to FPSC and, alternatively, that the Commission's decisions were arbitrary and unsupported by competent evidence.[57] The Florida Supreme Court disagreed, writing in May 2013 that "it is not this Court's function to substitute its judgment for that of the Legislature as to the wisdom or policy of a particular statute."[58] Subsequently, the Florida legislature passed a change in the law that would require a utility to

48. Petition for Limited Proceeding to Approve Stipulation and Settlement Agreement by Progress Energy Florida, Inc., Order No. PSC-12-0104-FOF-E1, Docket No. 120022-EI, at 8 (Fla. P.S.C. Mar. 8, 2012).

49. *Id.* at 1.

50. *Id.* at 5, 19.

51. Petition for Increase in Rates by Florida Power & Light Company, Order No. PSC-11-0089-S-EI, Docket No. 080677-EI, at 14 (Fla. P.S.C. Feb. 1, 2011).

52. Petition for Rate Increase by Florida Power & Light Company, Docket No. 120015-EI (Fla. P.S.C. Mar. 19, 2012).

53. *Id.* at 25.

54. Petition for Rate Increase by Florida Power & Light Company, Order No. PSC-13-0023-S-EI, Docket No. 120015-EI, at 11 (Fla. P.S.C. Jan. 14, 2013).

55. *Id.* at 16. $165.3 million in June 2013 when the Cape Canaveral modernization in-service, $234 million in June 2014 with Riviera plant modernization in-service, and $216 million in June 2016 with Port Everglades plant modernization in-service.

56. FLA. STAT. § 366.93 (2013); FLA. ADMIN. CODE r. 25-6.0423 (2013).

57. Southern Alliance for Clean Energy v. Graham, 113 So. 3d 742, 745 (Fla. 2013).

58. *Id.* (citing State v. Rife, 789 So. 2d 288, 292 (Fla. 2001)).

complete construction of the nuclear plant within ten years to be allowed to collect the advance fee.[59]

B. North Carolina

On April 12, 2013, the Supreme Court of North Carolina issued a decision in *State ex rel. Utilities Commission v. Cooper*.[60] In this case, the Court considered "whether the order by the North Carolina Utilities Commission (NCUC) approving a 10.5% ROE for Duke Energy Carolinas, LLC (Duke) contained sufficient findings of fact to demonstrate that it was supported by competent, material, and substantial evidence in view of the entire record."[61] The court reviewed the evidence on the ROE admitted during the evidentiary hearing on the rate case and partial settlement.[62] The court concluded that "although the 10.5% ROE contained in the non-unanimous Stipulation fell within the range of ROEs recommended by the witnesses at the evidentiary hearing, . . . none of the witnesses specifically recommended a ROE of 10.5% based upon their calculations."[63] The court was particularly concerned that the Commission's order did not weigh the ROE testimony presented at the evidentiary hearing, which as a mere recitation of the witnesses' testimony was inadequate to justify the ROE adopted by the NCUC.[64] For the foregoing reasons, the court reversed the NCUC's order and remanded the case to the Commission with instructions to make an independent determination regarding the proper ROE based upon appropriate findings of fact that weigh all the available evidence.[65]

C. South Carolina

In *Carolina Water Service, Inc. v. South Carolina Office of Regulatory Staff*,[66] Carolina Water Service, Inc. (CWS) appealed an order of the Public Service Commission, arguing that the PSC improperly denied it rate relief solely on the basis of unacceptable quality of service.[67] Under South Carolina law, a utility's initial application creates a prima facie case that the costs are reasonable and prudent: "The utility company is entitled to the presumption of reasonableness in expenditures[,] and the Commission must consider the actual expenditures undertaken and any increase in expenses that may entitle Carolina Water to some rate increase."[68] With regard to the facts at hand, the court held that the Commission's order citing customer complaints about service quality at

59. S. 1472, 23d Leg., Reg. Sess. § 1(3)(f)1.a (Fla. 2013).

60. State *ex rel.* Utils. Comm'n v. Cooper, 739 S.E. 2d 541 (N.C. 2013).

61. *Id.* at 542.

62. *Id.* at 542-44.

63. *Id.* at 547.

64. *Id.*

65. *Id.* at 548.

66. Carolina Water Serv., Inc. v. South Carolina Office of Regulatory Staff, No. 2012-208126, slip op. at 1 (S.C. Mar. 29, 2013) (per curiam).

67. *Id.*

68. *Id.*

public hearings did not provide a basis for disallowing costs.[69] The court reversed the decision and remanded to the PSC for a more detailed order.[70]

D. Virginia

1. Utility Acquisition of Coal-Fired Generation

On July 31, 2013, the Virginia State Corporation Commission (VA SCC) ruled on a restructuring case involving American Electric Power (AEP), wherein Appalachian Power Company (APCo) sought to acquire coal plants formerly owned by another AEP affiliate, Ohio Power, and to merge with another AEP affiliate, Wheeling Power, which provides service in West Virginia.[71] The two coal plants at issue were the 2900 megawatts (MW) John Amos generating plant in Winfield, West Virginia (in which APCo already owned two of the units and a third of the remaining unit), and the two-unit 1560 MW Mitchell Plant, located near Moundsville, West Virginia.[72] APCo proposed to acquire the remainder of the third unit of the Amos plant and a 50% interest in the Mitchell plant, at their net book values at the time of acquisition, approximately $618 and $536 million, respectively.[73]

The VA SCC allowed APCo to acquire the remaining interest in the Amos 3 plant from an affiliate company at a price of $565 million—$53.4 million lower than the price APCo proposed to pay.[74] The VA SCC rejected APCo's request to purchase half of the Mitchell plant, reasoning that Mitchell was a riskier investment because APCo had no track record of operating and maintaining the Mitchell plant or knowledge of all potential environmental and contractual risks associated with Mitchell.[75] Moreover, the VA SCC considered "it relevant and important that APCo already owns [most of the Amos plant and] Virginia ratepayers already have made substantial investments in the Amos units."[76] The VA SCC also noted that it based its decision in part on the lack of diversity in APCo's generating fleet.[77] Approving both acquisitions would raise the percentage of coal-fired electricity produced by APCo's generation fleet to a projected 87% by 2017.[78] The VA SCC approved APCo's request to merge with Wheeling and ordered a $3.3 million credit to ratepayers.[79]

69. *Id.*

70. *Id.*

71. Application of Appalachian Power Company for Approval of Transactions to Acquire Interests in the Amos and Mitchell Plants at 1, Case No. PUE-2012-00141 (Va. Corp. Comm'n July 31, 2013).

72. *Id.* at 1-2.

73. *Id.* at 2.

74. *Id.* at 10.

75. *Id.* at 6-7.

76. *Id.*

77. *Id.* at 8.

78. *Id.*

79. *Id.* at 11-12.

E. West Virginia

1. Special Industrial Rate

In March 2012, the West Virginia Legislature passed H.B. 101, authorizing the West Virginia Public Service Commission (WV PSC) to consider allowing a special rate for electricity for energy intensive industrial consumers under certain circumstances.[80] This legislation was designed to benefit West Virginia's economy, the business climate in the state, residents through job creation, and other electric ratepayers by maintaining benefits of the energy intensive customers on the system.[81] However, the legislature directed that a special rate was not to "impose an unreasonable burden upon electric public utilities or other customers."[82]

In May 2012, Century Aluminum of West Virginia, Inc., (Century) filed a petition requesting approval of a special rate that fluctuated with the price of aluminum for its purchase of electricity from APCo in order to restart its aluminum smelter located in Ravenswood, West Virginia.[83] Under Century's proposal, the risk of revenue shortfalls would be placed on other APCo customers.[84] On October 4, 2012, the Commission issued an Order that established a special rate mechanism.[85] However, the WV PSC's rejected Century's proposal to place the risk of revenue shortfalls on other AEP customers and required Century and its parent company to enter into a corporate guarantee in order to minimize the risks of shortfalls.[86] The WV PSC granted hearing for reconsideration and considered two alternative rate proposals that did not require a guarantee.[87] On December 14, 2012, the WV PSC denied Century's request for reconsideration.[88] The WV PSC provided that Century could reopen its smelter plant either by utilizing the special rate mechanism established in the October 4 order or by pursuing discussions with the other parties to reach agreement on an alternative.[89]

80. W.VA. CODE § 24-2-1j (2013).

81. *Id.* § 24-2-1j(a)(5).

82. *Id.* § 24-2-1j(a)(6).

83. Petition of Century Aluminum of West Virginia, Inc. for Approval of a Special Rate for Purchase of Electricity at 2, Century Aluminum of West Virginia, Inc., Case No. 12-0613-E-PC (W. Va. P.S.C. May 11, 2012).

84. *Id.* at 6.

85. Century Aluminum of West Virginia, Inc., Case No. 12-0613-E-PC, at 1 (W. Va. P.S.C. Oct. 4, 2012).

86. *Id.* at 33, 69.

87. Century Aluminum of West Virginia, Inc., Case No. 12-0613-E-PC, at 1 (W. Va. P.S.C. Nov. 16, 2012).

88. Century Aluminum of West Virginia, Inc., Case No. 12-0613-E-PC, at 1 (W. Va. P.S.C. Dec. 14, 2012).

89. *Id.* at 17.

III. MID-WESTERN REGION

A. Indiana

1. Legislation

In 2013, the Indiana General Assembly adopted legislation designed to limit the amount of time available to conduct a rate case and to allow a utility to request a new tracker for transmission and distribution infrastructure investments under Senate Bill 560 (SB 560).[90]

The portion of the law dealing with rate case procedure provides that the Indiana Utility Regulatory Commission must issue a rate case order within 300 days after the utility files its complete case-in-chief, or the utility has the option to auto-implement 50% of the utility's proposed permanent increase in basic rates and charges pending the Commission's final order.[91] The Commission may extend the 300 days one time, for good cause, by an additional sixty days.[92] If the utility auto-implements a rate in excess of what the Commission authorizes in its final order, the utility must return all over-collected amounts with interest.[93]

The legislation also gives utilities the option of using a historic, hybrid or future test year.[94] Prior to the passage of SB 560, Indiana solely used a historic test year.[95] A historic test year must end no more than 270 days before the utility files its rate case petition.[96] A hybrid test period must use twelve consecutive months of combined historic and projected data.[97] A forward-looking test year is based on projected data for a twelve month period beginning not later than twenty-four months after the date on which the utility petitions the Commission for a rate change.[98] The utility cannot implement a rate increase before the date on which the projected data period begins.[99]

SB 560 also allows a public utility to request an automatic rate adjustment for transmission, distribution, and storage-system improvement investments (TDSIC).[100] Consideration of a TDSIC is in two parts.[101] First, the utility must file a seven year plan of eligible transmission, distribution and storage-system improvements.[102] "Eligible transmission, distribution and, storage system improvements" are defined as "new or replacement electric or gas transmission, distribution, or storage utility projects that a public utility undertakes for the purposes of safety, reliability, system monitorization, or economic development,

90. S. 560, 118th Gen. Assemb., 1st Reg. Sess. (Ind. 2013).
91. IND. CODE § 8-1-2-42.7(e) (2013).
92. *Id.* § 8-1-2-42.7(h).
93. *Id.* § 8-1-2-42.7(i).
94. *Id.* § 8-1-2-42.7(d).
95. *Id.* § 8-1-2-42.7(d)(2).
96. *Id.*
97. *Id.* § 8-1-2-42.7(d)(3).
98. *Id.* § 8-1-2-42.7(d)(1).
99. *Id.* § 8-1-2-42.7(e).
100. *Id.* §§ 8-1-39-1 to -16.
101. *Id.*
102. *Id.* § 8-1-39-9.

including the extension of gas service into rural areas."[103] The Commission has 210 days after the public utility files its petition and seven year plan to issue an order.[104] The Order must include "a finding of the best estimate of the costs of the eligible improvements included in the plan" make "a determination whether the public convenience and necessity require, or will require, the eligible improvements included in the plan" and make "a determination as to whether the estimated cost of the eligible improvements included in the plan are justified by the incremental benefits attributable to the plan."[105] If the Commission approves the utility's seven year plan, the utility may make a separate filing to determine the amount of the tracked charge.[106] The Commission has ninety days to address that filing. A utility may only track 80% of the eligible TDSIC improvements.[107] The remaining 20% is to be deferred until the utility's next rate case.[108] If the utility exceeds its estimate, it must specifically justify any additional costs.[109] Moreover, a utility must file a base rate case before the expiration of its seven year plan.[110] The Commission cannot approve a TDSIC that would result in an average aggregate increase in the public utility's total retail revenues of more than 2% in a twelve month period.[111]

2. Duke IGCC Revisited

In 2010, Duke Energy Indiana filed a request to update its approved construction estimate for an Integrated Gas Combined Cycle (IGCC) generation plant.[112] Duke proposed to increase its original estimate of $1.985 billion, which was updated once before and approved by the Indiana Utility Regulatory Commission's (IURC) at $2.35 billion,[113] to $2.88 billion.[114]

On April 30, 2012, parties to the proceeding entered into a settlement agreement with Duke that, inter alia, proposed to cap Duke's recovery of capital costs and allowance for funds used during construction (AFUDC) on the project at $2.595 billion as of June 30, 2012.[115] On December 27, 2012, a slightly

103. *Id.* § 8-1-39-2.
104. *Id*. § 8-1-39-10.
105. *Id.*
106. *Id.* § 8-1-39-12.
107. *Id.* § 8-1-39-9.
108. *Id.*
109. *Id.*
110. *Id.*
111. *Id.* § 8-1-39-14.
112. Verified Petition of Duke Energy Indiana, Inc. Seeking Approval of an Ongoing Review Progress Report, Cause No. 43114-IGCC-4-SI (Ind. Util. Regulatory Comm'n Jan. 27, 2010) (prehearing conference order).
113. Verified Petition of Duke Energy Indiana, Inc. Seeking Authority to Reflect Costs Incurred for the Edwardsport IGCC Project Cause No. 43114-IGCC-1, at 1, 11 (Ind. Util. Regulatory Comm'n Jan. 7, 2009).
114. Verified Petition of Duke Energy Indiana, Inc. Seeking Approval of an Ongoing Review Progress Report, Cause No. 43114-IGCC-4-SI, at 8 (Ind. Util. Regulatory Comm'n Dec. 27, 2012).
115. *Id.* at 9.

modified version of the settlement agreement was approved.[116] An appeal of the order is pending, and currently the IGCC facility is operating.[117]

B. Michigan

On July 1, 2013, Michigan Governor Rick Snyder signed 2013 PA 95 (Act 95) into law.[118] Act 95 creates the Low-Income Energy Assistance Fund (LIEAF) within the State Treasury.[119] Act 95 provides that money from the LIEAF shall be expended by the Department of Human Services as provided in the Michigan Energy Assistance Act.[120] The Michigan Public Service Commission (MPSC) may annually approve a funding factor,[121] which establishes a nonbypassable surcharge to be added to each retail billing meter.[122] In July 2013, the MPSC issued an order seeking additional information from the utilities regarding implementation of Act 95; this proceeding is pending.[123]

The MPSC accepted the MPSC Staff's Report on Advanced Metering Infrastructure and Smart Grid on September 11, 2012.[124] The MPSC noted that Advanced Metering Infrastructure (AMI) and smart grid investments "should be reviewed in the context of general rate case proceedings" and commented that interested parties should continue "to refine the scope of, and quantify and assess the costs and benefits of AMI and smart grid during the implementation of these new technologies on a case-by-case basis."[125] Further, should a utility decide to implement AMI or smart grid, opt-out options and/or tariffs shall be made available, based on cost-of-service principles, for the utilities' customers.[126] Additionally, because these technological advances present complex issues of customer data collection, privacy, and cyber security, the MPSC plans to create a future docket limited to these issues, where the MPSC will solicit company-specific information on cyber security planning, standards, and policies for the utilities currently implementing AMI or planning to implement these systems.[127]

A Renewable Energy Amendment to the Michigan State Constitution, known as "Proposal 3" was defeated in a statewide ballot.[128] The proposal would have added a new section 55 to article 4 of the state constitution and

116. *Id.* at 121.

117. Citizens Action Coal. of Ind., Inc. v. Duke Energy Ind., Inc., No. 93A02-1301-EX-76 (Ind. Ct. App. filed Jan. 25, 2013).

118. MICH. COMP. LAWS § 460.9t (2013), *amended by* S. 284, 97th Leg., Reg. Sess. (Mich. 2013) (amending 1939 Mich. Pub. Acts 3)).

119. MICH. COMP. LAWS § 460.9t (2013).

120. *Id.* § 460.9t(5).

121. *Id.* § 460.9t(6).

122. *Id.* § 460.9t(10)(b).

123. Implement the Provision of 2013 PA 95, Case No. U-17377, 2013 WL 3756600 (Mich. P.S.C. July 11, 2013) (order and notice of opportunity to comment).

124. Commission's Own Motion to Review Issues Bearing on the Deployment of Smart Meters by Regulated Electric Utilities in Michigan, Case No. U-17000, at 4 (Mich. P.S.C. Sept. 11, 2012).

125. *Id.*

126. *Id.*

127. *Id.* at 6.

128. Melissa Anders, *Michigan Proposal 3: Voters Reject 25 by 25 Renewable Energy Mandate*, MLIVE (Nov. 7, 2012), http://www.mlive.com/politics/index.ssf/2012/11/proposal_3_michigans_renewable.html.

would have required 25% of electricity to be generated from renewable energy sources by 2025.[129] The margin of defeat was 62% of voters against the amendment and 38% in favor of the amendment.[130]

C. Ohio

1. Combined Heat and Power

On April 13, 2012, Governor John Kasich signed into law Substitute Senate Bill 289 permitting energy produced from cogeneration technology to qualify as a renewable energy resource under the state's alternative electric energy resource requirements,[131] as well as advanced energy project loans and grants.[132] Under Ohio's Alternative-Energy Portfolio Standard, electric distribution utilities and electric services companies are required to secure 25% of their electricity supplies from alternative energy resources, of which 12.5% must come from renewable energy resources, by 2025.[133]

2. Securitization

On December 21, 2011, Gov. Kasich signed HB 364 establishing Sections 4928.23 through 4928.2318 of the Revised Code for the purpose of providing electric distribution utilities (EDUs) with the mechanism to securitize, through the issuance of phase-in-recovery (PIR) bonds, certain debt previously approved by the Public Utilities Commission of Ohio (PUCO).[134] This statute provides that an EDU may seek a financing order from the Commission to securitize deferred assets, such as fuel costs, infrastructure costs, and environmental clean-up expenses that the Commission allows the EDU to defer and collect from customers.[135] On May 3, 2012, FirstEnergy affiliates Ohio Edison, the Cleveland Illuminating Company, and Toledo Edison filed an application, pursuant to section 4928.231 of the Revised Code, seeking authority to recover phase-in costs and financing costs, issue PIR Bonds, and impose and collect PIR charges.[136] In addition, FirstEnergy requested tariff and bill format approvals.[137] On October 10, 2012, the PUCO approved FirstEnergy's application to

129. MI ENERGY, MI JOBS, FULL TEXT OF PROPOSED CONSTITUTIONAL AMENDMENT (2012), *available at* http://www.michigan.gov/documents/sos/Full_Text_-_MI_Energy_MI_Jobs_399441_7.pdf; *see also* HOUSE FISCAL AGENCY, BALLOT PROPOSAL 3 OF 2012 (2012), *available at* http://www.house.michigan.gov/hfa/PDF/Alpha/ballotproposal2012_3.pdf.

130. *Summary Totals: State Proposal – 12-3: Constitutional Amendment: Establish a Standard for Renewable Energy*, MICH. DEP'T OF STATE, http://miboecfr.nictusa.com/election/results/12GEN/90000003.html (last visited Oct. 18, 2013).

131. OHIO REV. CODE § 4928.64(A)(1)(b) (2012).

132. *Id.* § 3706.25(B)(2).

133. *Id.* § 4928.64(B).

134. *Id.* § 4928.23.

135. *Id.*

136. Application for Financing Order, Joint Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1465-EL-ATS (Ohio P.U.C. May 3, 2012).

137. *Id.* at 16.

securitize $555 million in previously approved deferred costs.[138] Under the PUCO's order, the new PIR replaced the existing Deferred Fuel Cost Recover Rider (DFC), Deferred Generation Cost Recovery Rider (DGC), and the Residential Electric Heating Recover Rider (RER1) with estimated savings for customers of approximately $104 million.[139] Conditions placed on the approval included the PUCO's retainer of an independent financial advisor to assist in reviewing the final financing terms upon the company's issuance of the bonds.[140] In addition, the PUCO retained co-equal decision making authority with FirstEnergy with respect to the structure and pricing of the bonds.[141] This approval resulted in approximately $106 million in savings for FirstEnergy's Ohio customers through 2035.[142] On July 31, 2012, AEP filed an application under Section 4928.231 of the Revised Code seeking authority to recover the phase-in costs and financing costs through the issuance of PIR bonds payable from the collection of PIR charges, and to impose and collect such PIR charges.[143] On March 20, 2013, the PUCO approved AEP's application to securitize approximately $298 million in previously approved deferred costs.[144] The PUCO's decision is estimated to save AEP's customers $28.8 million.[145]

3. Electric Security Plan

On August 8, 2012, the PUCO approved AEP's modified electric security plan (ESP) that permits AEP to transition to a fully competitive market based structure by June 1, 2015.[146] In addition, the decision froze AEP's base generation rates through May, 31, 2015.[147] AEP will auction 10% of its standard service offer (SSO) load beginning in 2013,[148] and in June 2014, 60% of AEP's SSO load will be provided by competitive auctions, increasing to 100% in January 2015.[149] As of June 1, 2015, AEP's SSO will be fully provided by

138. Joint Application of Ohio Edison Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1465-EL-ATS (Ohio P.U.C. Oct. 10, 2012) (financing order).

139. *Id.* at 31.

140. *Id.* at 43.

141. *Id.*

142. Press Release, FirstEnergy Corp., FirstEnergy's Ohio Utilities to Reduce Customer Costs by $106 Million Through Securitization Transaction: First Ohio Utils. to Take Advantage of State's New Securitization Law (June 20, 2013), *available at* https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy-s-ohio-utilities-to-reduce-customer-costs-by--106-mi.html.

143. Application, Application of Ohio Power Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1969-EL-ATS (Ohio P.U.C. Jul. 31, 2012).

144. Application of Ohio Power Company for Authority to Issue Phase-In-Recovery Bonds, Case No. 12-1969-EL-ATS, at 45 (Ohio P.U.C. Mar. 20, 2013) (financing order).

145. Press Release, Pub. Utils. Comm'n of Ohio, PUCO Approves AEP-Ohio Securitization Application (Mar. 20, 2013), *available at* http://www.puco.ohio.gov/puco/index.cfm/media-room/media-releases/puco-approves-aep-ohio-securitization-application/.

146. Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer, Case Nos. 11-346-EL-SSO; 11-348-EL-SSO, at 59 (Ohio P.U.C. Aug. 8, 2012).

147. *Id.* at 31-32.

148. *Id.* at 39.

149. *Id.* at 40.

competitive auctions.[150] To further mitigate rate impacts on customers, the PUCO imposed a rate cap where no customer rate increase will exceed 12% during the term of the ESP.[151] A modified version of AEP's original application was approved by the PUCO in December 2011[152] and subsequently revoked in February 2012 after the PUCO determined that its prior decision did not serve the public interest.[153]

In addition, on April 13, 2012, FirstEnergy filed an agreement with a wide range of stakeholders to extend the current ESP through May 2016.[154] Generation prices would continue to be set by the competitive bidding process, but the bids scheduled to occur in October 2013 and January 2013 would be for a three-year period, instead of a one-year period.[155] This agreement is a continuation of FirstEnergy's current ESP that is in effect from June 2011 through May 2014.[156] Under the current ESP, generation rates are determined through a competitive bid process.[157] The competitive bid process was to be conducted by an independent bid manager each January through 2013.[158] FirstEnergy's base distribution rates will remain frozen through May 2014.[159] The PUCO approved the settlement agreement on July 18, 2012.[160]

D. Wisconsin

The Public Service Commission of Wisconsin (PSCW) completed its Final Strategic Energy Assessment: Energy 2016 (the Assessment) in February 2011.[161] The Assessment projected peak demand growth for 2011-2016 to increase at a rate of 1% per year.[162] The Assessment also found the planning

150. *Id.* at 39-40.

151. *Id.* at 70.

152. Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer, Case Nos. 11-346-EL-SSO; 11-348-EL-SSO, at 66 (Ohio P.U.C. Dec. 14, 2011).

153. Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer, Case Nos. 11-346-EL-SSO; 11-348-EL-SSO, at 2, 4 (Ohio P.U.C. Feb. 23, 2012) (entry on rehearing).

154. Application at 2, Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer, Case No. 12-1230-EL-SSO (Ohio P.U.C. Apr. 13, 2012).

155. *Id.*

156. Application at 33, Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, for Authority to Provide for a Standard Service Offer, Case No. 12-1230-EL-SSO (Ohio P.U.C. Mar. 23, 2010).

157. Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, for Authority to Provide for a Standard Service Offer, Case No. 10-388-EL-SSO, at 8 (Ohio P.U.C. Aug. 25, 2010).

158. *Id.*

159. *Id.* at 34.

160. Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer, Case No. 12-1230-EL-SSO, at 58 (Ohio P.U.C. July 18, 2012).

161. PUB. SERV. COMM'N OF WIS., FINAL STRATEGIC ENERGY ASSESSMENT: ENERGY 2016 (2011) [hereinafter ENERGY ASSESSMENT 2016].

162. *Id.* at 3.

reserve margin forecast through 2016 to be above 15%.[163] The Assessment noted that the Commission is participating in multiple regional transmission studies to explore possible future transmission scenarios and how costs may be shared among all states that benefit from the additional capacity.[164]

The PSCW accepted the final status report regarding implementation of advanced renewable tariffs (ARTs) in Wisconsin.[165] At the outset of this investigation, the Commission noted that it was limited by both federal and state law in its authority to issue ARTs.[166] On July 15, 2010, the Federal Energy Regulatory Commission (FERC) issued a declaratory order on feed-in tariffs in response to separate petitions from the state of California and California utilities.[167] The FERC's order directly addressed the question of how federal statutes limit a state's authority to order ARTs.[168] The FERC ruled that states may indeed order a utility to purchase electricity at a long-term, fixed price set by the state (i.e. a feed-in tariff), but only if the seller is a Public Utility Regulatory Policies Act (PURPA) "qualifying facility" and only if the price is set no higher than the utility's avoided costs.[169] On October 21, 2010, the FERC issued a clarification of its declaratory order in response to a subsequent petition from the California Public Utilities Commission (CPUC) and the California utilities.[170] The FERC clarified that limitations imposed by state law can be factored into avoided cost calculations.[171] The Commission expounded that these FERC rulings could have a significant impact in Wisconsin, not just for feed-in tariffs but also for ordinary parallel generation tariffs, because of Wisconsin's renewable portfolio standards.[172] The Commission noted that regardless of the interpretations of the PURPA or the Federal Power Act (FPA) by the FERC or other states, the Wisconsin statutes (chapter 196) are still in place and limit the Commission's authority to order ARTs.[173]

The PSCW approved the application of the American Transmission Company to construct a new 5.8 mile, 345 kilovolt (kV) transmission line from the existing Pleasant Prairie switchyard to the existing Zion Energy Center.[174] The approval of this application was unique in that the purpose of the project is primarily economic, and the project was not addressing a specific reliability issue.[175] The total estimated cost was approximately $30 million.[176] The PSCW

163. *Id.*

164. *Id.*

165. Minutes and Informal Instructions, Investigation on the Commission's Own Motion Regarding Advanced Renewable Tariff Development, No. 5-EI-148 (Wis. P.S.C. Dec. 22, 2010).

166. ENERGY ASSESSMENT 2016, *supra* note 161, at 5.

167. *California Public Utilities Commission*, 132 F.E.R.C. ¶ 61,047 (2010).

168. *Id.* at P 53.

169. *Id.* at P 31.

170. *California Public Utilities Commission*, 133 F.E.R.C. ¶ 61,059 (2010).

171. *Id.* at P 30.

172. ENERGY ASSESSMENT 2016, *supra* note 161, at 34 n.9.

173. *Id.* at 9.

174. Application by American Transmission Company to Construct a New 5.8-Mile 345 kV Transmission Line from the Existing Pleasant Prairie Switchyard to the Existing Zion Energy, No. 137-CE-161, at 22 (Wis. P.S.C. May 7, 2012).

175. *Id.* at 5.

also approved the CapX2020 Alma-La Crosse Transmission Project, a part of the CapX2020 Transmission Expansion Initiative.[177] The Wisconsin portion of this project was to address reliability in the La Crosse local area and provide regional benefits.[178] Additionally, the project impacts the long range plans for the area, as it will increase transfer capability.[179] The estimated cost for the project was $210 million.[180] The PSCW also approved two applications from the Northern States Power Company-Wisconsin: the Stone Lake-Couderay Transmission Project[181] and the Couderay-Osprey 161/69 kV Transmission Line and Substation Upgrade Project.[182] The Stone Lake-Couderay Project was estimated to cost over $28 million,[183] and the Couderay-Osprey Project was estimated to cost over $46 million.[184]

The PSCW granted Wisconsin Electric Power Company (WEPCO) a Certificate of Authority to construct, install, and place in utility service a 50 megawatt (MW) biomass-fueled cogeneration facility for the production of electricity at the Domtar Paper Company, LLC (Domtar) facility in the village of Rothschild, Wisconsin.[185] The proposed facility will produce electricity and steam, and will diversify WEPCO's portfolio of renewable resources.[186] The estimated cost was $255 million, and the Commission found that as proposed, the ratepayers were being asked to pay a disproportionate share of the cost, as the steam will largely benefit just Domtar.[187] The Certificate of Authority was granted, though it was conditioned upon reanalyzing the cost allocation to the ratepayers and to Domtar.[188]

The PSCW approved Wisconsin Power and Light Company's application to purchase Riverside Energy Center, LLC, which includes a 600 MW combined cycle generating facility in Beloit, Wisconsin, for a purchase price of $392 million.[189] The PSCW also approved Wisconsin Public Service Corporation's

176. *Id.* at 3.

177. Application of Dairyland Power Cooperative, Northern States Power Company-Wisconsin, and Wisconsin Public Power, Inc., for Authority to Construct and Place in Service 345 kV Electric Transmission Lines and Electric Substation Facilities, No. 5-CE-136, at 48 (Wis. P.S.C. May 30, 2012).

178. *Id.* at 7.

179. *Id.* at 11.

180. *Id.* at 4.

181. Application of Northern States Power Company-Wisconsin to Upgrade Electric Transmission Facilities Between Existing Stone Lake and Couderay Substations, No. 4220-CE-176, at 25 (Wis. P.S.C. Sept. 27, 2012).

182. Application of Northern States Power Company-Wisconsin to Remove, Replace, and Double-Circuit 36 Miles of Transmission Facilities, No. 4220-CE-178, at 18 (Wis. P.S.C. Oct. 25, 2012).

183. Application of Northern States Power Company-Wisconsin to Upgrade Electric Transmission Facilities Between Existing Stone Lake and Couderay Substations, No. 4220-CE-176, at 24-25 (Wis. P.S.C. Sept. 27, 2012).

184. Application of Northern States Power Company-Wisconsin to Remove, Replace, and Double-Circuit 36 Miles of Transmission Facilities, No. 4220-CE-178, at 3 (Wis. P.S.C. Oct. 25, 2012).

185. Application of Wisconsin Electric Power Company for Authority to Build and Operate a 50 MW, Biomass-Fired, Cogeneration Facility, No. 6630-CE-305, at 2 (Wis. P.S.C. May 12, 2011).

186. *Id.* at 3-4.

187. *Id.* at 4, 18-19.

188. *Id.* at 2.

189. Application of Wisconsin Power and Light Company for Approval to Purchase the Riverside Energy Center from Riverside Energy Center, LLC, No. 6680-EB-I05, at 14 (Wis. P.S.C. Apr. 13, 2012).

application to purchase Fox Energy Company, LLC, which includes the Fox Energy Center, a natural gas fired combined cycle electricity generation facility with capacity of 593 MW, for a purchase price of $390 million.[190]

IV. WESTERN AND SOUTHWESTERN REGION

A. Arizona

On May 24, 2012, the Arizona Corporation Commission (ACC) issued a decision in the Arizona Public Service Company (APS) rate case (the Decision).[191] The Decision followed an evidentiary hearing on a settlement agreement[192] reached by most of the parties in the proceeding.[193] The Decision resulted in an overall zero dollar base rate increase because the non-fuel base rate increase was offset by a fuel rate base decrease.[194] The Decision also included a four-year stay out.[195] The ACC approved a fair value rate base of $8,167,121,000, and a fair value rate of return of 6.09%.[196] The return on equity was 10.0%.[197]

The Decision included several items of interest. First, the ACC approved a lost fixed cost recovery mechanism (LFCR) which, in effect, is a limited revenue decoupling plan to help address the lost revenue due to energy efficiency (EE) and distributed generation (DG).[198] Second, cost recovery for certain renewable energy investments was transferred from a renewable energy surcharge to base rates.[199] Third, the ACC approved a mechanism to increase rates further if APS acquires Southern California Edison's ownership of the Four Corners coal plant.[200] Fourth, the ACC approved an experimental rate schedule, AG-1, which is a "buy through rate" for large commercial and industrial customers.[201]

Under the LFCR, APS recovers a portion of distribution and transmission costs associated with residential, commercial, and industrial customers when sales levels are reduced by EE and DG.[202]

190. Application of Wisconsin Public Service Corporation for Authority to Purchase Fox Energy Company, LLC, and Place in Service Fox Energy Center, No. 6690-EB-105 (Wis. P.S.C. Feb. 22, 2013).

191. Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, Decision No. 73183, Docket No. E-01345A-11-0224 (Ariz. Corp. Comm'n May 24, 2012).

192. Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, Docket No. E-01345A-11-0224 (Ariz. Corp. Comm'n Jan. 6, 2012) (notice of filing settlement agreement).

193. Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, Decision No. 73183, Docket No. E-01345A-11-0224, at 4 (Ariz. Corp. Comm'n May 24, 2012).

194. *Id.* at 11.

195. *Id.* at 10.

196. *Id.* exhibit A at 6.

197. *Id.* at 46.

198. *Id.* at 12-15.

199. *Id.* at 23.

200. *Id.* at 15.

201. *Id.* at 16, 24.

202. *Id.* at 12-13.

The LFCR is adjusted annually with an annual 1% cap on increases.[203] The LFCR does not apply to certain large customers whose rate schedules were modified to address uncovered fixed costs through changes in rate design with enhanced demand and basic service charges (BSC) and a corresponding adjustment to energy charges.[204] Residential customers may opt out of the LFCR by electing an optional BSC.[205]

Another significant provision of the Decision is a change in the cost recovery mechanism for some renewable energy investments.[206] These renewable energy investments will be put in the rate base and recovered through base rates instead of through the renewable energy adjustor.[207] As a result, the renewable energy adjustor rate is reduced, but the rate base is increased.[208] APS can then earn a return on the renewable investments.[209]

At the time of the rate case, APS was in the process of acquiring Southern California Edison's share of the Four Corners power plant units 4 and 5.[210] The ACC agreed to hold the rate case open in order for APS to make a future filing to increase its rates to reflect the investment in Four Corners.[211] As a result, APS will avoid regulatory lag by filing a "mini" rate case that will allow an adjustment to the rates without waiting for the next full rate case after the four year stay-out.[212]

Finally, in a response to large customers' interest in retail competition, the ACC adopted an Experimental Rate Schedule AG-1.[213] APS can sell up to 200 MW of power to certain large customers at a "wholesale" rate although APS has to make commercially reasonable efforts to eliminate or mitigate all unrecovered costs resulting from these sales.[214]

B. California

The California Public Utilities Commission (Commission or CPUC) adopted rules to protect the privacy and security of customer data generated by smart meters deployed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Electric Utilities).[215] The rules implement the protections ordered by California Senate Bill 1476 (chapter 497, statutes of 2010), which seeks to protect the privacy of usage information, and applied to the Electric Utilities as well as certain third parties—those that assist in utility

203. *Id.* at 13.
204. *Id.* at 27-28.
205. *Id.* at 28-30.
206. *Id.* at 12.
207. *Id.*
208. *Id.*
209. *Id.* exhibit A at 9-10.
210. *Id.* at 15.
211. *Id.*
212. *Id.*
213. *Id.* at 16, 24.
214. *Id.* at 24.
215. Order Instituting Rulemaking to Consider Smart Grid Technologies, Decision 11-07-056, Rulemaking 08-12-009, at 2 (Cal. P.U.C. July 29, 2011).

operations and those that gain access to the customer's usage data directly from the utility.[216] In so doing, the Commission adopted the Fair Information Practices (FIP) principles as a guide for developing policies and regulations aiming to protect the privacy and security of electricity usage data of consumers.[217] The Commission stated that the rules and policies it adopted are consistent with privacy and security principles adopted by the Department of Homeland Security.[218] The Commission also adopted policies to govern access to customer usage data by customers and by authorized third parties, including information as to pricing, usage, and cost in a customer-friendly manner.[219] This decision did not apply to other electric corporations, gas corporations, community choice aggregators, or electric service providers, but the Commission opened a new phase of the proceeding to explore how the rules should apply to such entities.[220]

The Commission also required the electric utilities to file a Tier 2 advice letter with the Commission detailing how they would provide retail price, wholesale price, usage, and bill data to customers using the disaggregated information provided by the smart meter.[221] This information is to be made online and updated, at least on a daily basis, with each day's usage data, along with applicable price and cost details and with hourly or fifteen-minute granularity available by the next day.[222] The Commission did not prescribe how a utility should make that information available, nor had it limited the information provided.[223] The Commission determined that the electric utilities and the California Independent System Operator (CAISO) should develop a cost-effective way of providing accessible information on prices in electric wholesale markets.[224]

The Commission also ordered the electric utilities, either separately or jointly, to initiate a pilot study to explore useful and cost-effective ways to provide price information in real-time or near real-time.[225] The Commission further required the electric utilities to develop plans for implementing a Home Area Network (HAN) program through the use of smart meters along with a number of strategies to increase functionality, privacy, and security of a HAN platform.[226] The Commission requested a timetable and plan for implementation to increase functionality and benefits for each electric utility, and it ordered each electric utility to complete an initial roll-out phase of 5000 HAN devices for early adopters so that energy usage data can be transmitted for data collection.[227]

216. *Id.* at 2, 11.
217. *Id.* at 19.
218. *Id.* at 5.
219. *Id.* at 2-3.
220. *Id.* at 5.
221. *Id.* at 105.
222. *Id.* at 3, 118.
223. *Id.* at 104-05.
224. *Id.* at 104.
225. *Id.* at 106.
226. *Id.* at 116.
227. *Id.*

The Commission approved, subject to certain requirements, a portfolio of energy efficiency programs and budgets to be implemented in 2013 and 2014 by PG&E, SDG&E, SCE, and SoCalGas, as well as two regional energy networks (RENs), San Francisco Bay Area Regional Energy Network and Southern California Regional Energy Network, and one community choice aggregator, Marin Energy Authority (MEA).[228] The Commission intended to facilitate energy and energy-related cost savings and to lock down the energy savings estimates for the programs.[229] The Commission also defined RENs, differentiated them from local government partnerships run by utilities, and identified certain roles and responsibilities for the REN proponents and the gas utilities.[230]

In Commission Decision 12-05-035, the Commission implemented statutory amendments to Public Utilities Code section 399.20 to adopt a new pricing mechanism for the Commission's Feed-in Tariff (FiT) Program.[231] The "new pricing mechanism [is] referred to as the 'Renewable Market Adjusting Tariff' or 'Re-MAT.'"[232] The Commission also adopted several new or revised FiT programs components, including, increasing the maximum size of eligible facilities to 3 MW, adjusting capacity allocations among the utilities, adopting project viability criteria, and excluding small electric utilities from the program.[233]

Thereafter, on May 23, 2013, the Commission ordered the three electric investor owned utilities (IOUs) to revise their FiT programs to include a new streamlined standard contract and revised tariffs.[234] The new streamlined standard contract incorporates the FiT program requirements already adopted in the Commission Decision 12-05-035, subject to modifications including changing the process used by the utilities to determine the amount of megawatts available for subscription for the three product types during each bi-monthly period.[235] The Commission also modified Decision 12-05-035 to direct PG&E and SCE to offer 5 MW (and SDG&E to offer 3 MW) in each product category—baseload, peaking as-available, and non-peaking as-available—during each bi-monthly period until the available megawatts for that product type fall below 5 MW (or 3 MW for SDG&E) and to continue to offer the remaining megawatts for the product type until the megawatts go to zero or the program ends.[236] The Commission also modified two aspects of the program to protect against unreasonable price increases, including establishing a cap on the total price period adjustment at $12 to avoid excess bi-monthly price adjustments and

228. Application of Pacific Gas and Electric Company for Approval of 2013-2014 Energy Efficiency Programs and Budget, Decision 12-11-015, Application 12-07-001, at 2 (Cal. P.U.C. Nov. 8, 2012).

229. *Id.* at 106.

230. *Id.* at 7-9, 11.

231. Order Instituting Rulemaking to Continue Implementation of California Renewables Portfolio Standard Program, Decision 12-05-035, Rulemaking 11-05-005, at 2 (Cal. P.U.C. May 24, 2012).

232. *Id.*

233. *Id.* at 3.

234. Order Instituting Rulemaking to Continue Implementation of California Renewables Portfolio Standard Program, Decision 13-05-034, Rulemaking 11-05-005, at 2 (Cal. P.U.C. May 23, 2013).

235. *Id.* at 3, 10-11, 14-15.

236. *Id.* at 12, 15.

changing the 50% threshold for triggering a price increase in a subsequent program period to less than 20% of capacity for the current period.[237]

The Commission issued a few decisions pertaining to the California Renewables Portfolio Standard program (RPS) during the relevant time period. For instance, on December 1, 2011, the Commission set the new RPS procurement quantity requirements offered by new Public Utilities Code section 399.15(b), for all retail sellers IOUs, community choice aggregators, and electric service providers).[238] The decision outlined procurement quantity requirements and set targeted goals for retail sellers for each RPS period through at least 2021.[239] For example, the decision provided that for the RPS period between 2011 and 2013, each retail seller must procure an average of 20% of its retail sales for the entire period from RPS-eligible resources.[240] By the year 2021, each retail seller must have sufficient procurement from RPS-eligible resources to meet its annual procurement quantity requirement of 33% of retail sales.[241]

In addition, on June 21, 2012, the Commission "implement[ed] changes to the rules for retail sellers' compliance with the [RPS] program made by Senate Bill (SB) 2 (1X)."[242] The Commission also set the "parameters for retail sellers to report to the Commission on their compliance with RPS requirements" and provided rules for retail sellers to complete a variety of tasks related to RPS.[243] The Commission noted that its decision implemented the most immediate compliance requirements but did not complete implementation of rules for the enforcement of RPS obligations under SB 2 (1X).[244]

With respect to net energy metering (NEM), on May 24, 2012, the Commission issued a decision regarding the calculation of the "net energy metering cap," as established in Public Utilities Code section 2827(c)(1).[245] This cap "limits the availability of electric utility [NEM] programs to eligible customer-generators in the utility service territory on a first-come-first-served basis until the total rated generating capacity used by eligible customer-generators exceeds [5%] of the utility's 'aggregate customer peak demand.'"[246] The Commission "clarifie[d] the denominator of the equation, defined in the statute as 'aggregate customer peak demand'" that the three electric IOUs "should use to calculate the [5% NEM] cap."[247] Specifically, the Commission

237. *Id.* at 12, 14-15.

238. Order Instituting Rulemaking to Continue Implementation of California Renewables Portfolio Standard Program, Decision 11-12-020, Rulemaking 11-05-005, at 2 (Cal. P.U.C. Dec. 1, 2011).

239. *Id.* at 2-3.

240. *Id.* at 2.

241. *Id.* at 3.

242. Order Instituting Rulemaking to Continue Implementation of California Renewables Portfolio Standard Program, Decision 12-06-038, Rulemaking 11-05-005 (Cal. P.U.C. June 21, 2012).

243. *Id.* at 2-3.

244. *Id.* at 3.

245. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues, Decision 12-05-036, Rulemaking 10-05-004, at 1 (Cal. P.U.C. May 24, 2012).

246. *Id.* at 1.

247. *Id.*

defined the "aggregate customer peak demand" as the highest sum of all customers' non-coincident peak demands that occurs in any calendar year.[248]

On September 13, 2012, the Commission approved a settlement that presents an essentially reformed Electric Tariff Rule 21 and related standardized forms, both of which collectively govern the interconnection by electric generating facilities to the distribution systems of PG&E, SCE, and SDG&E.[249] The reformed tariff introduces a series of steps to implement distribution-level interconnection queues to get away from the "first-come, first-served" approach to interconnection processing used in the former Rule 21.[250] Finally, the revised Rule 21 was found to address the limitation of aggregate generating capacity on a line section to 15% of that line section's peak load, by retaining the 15% of peak load screen but allowing interconnection applicants that fail the 15% of peak load screen to subject themselves to further evaluation of aggregate generating capacity on the line section against 100% of minimum load.[251] The Commission determined that in establishing this second screen in supplemental review, the revised Rule 21 "permits higher penetration levels of distributed generation without significantly increasing the time or expense of the interconnection process."[252] The Commission also found that the revised Rule 21 introduces the term "storage" to the definition of generating facility so as to provide clarity that this rule creates distribution-level procedures for storage technologies.[253]

C. Colorado

Since 2011, Colorado legislators and regulators have been busy living up to the reputation that goes along with being from the state that claims credit for originating the phrase "New Energy Economy."[254] This has included efforts to implement previously enacted energy legislation, passage of new legislation, proactive regulatory investigations, and a number of noteworthy individual regulatory dockets.[255]

In April 2010, then-Governor Bill Ritter signed into law House Bill 10-1365, the Clean Air–Clean Jobs Act.[256] The Act required Colorado's investor-owned electric utilities—Public Service Company of Colorado (PSCo) and Black Hills Energy (BHE)—to develop emissions reduction plans (ERPs)

248. *Id.* at 6.

249. Order Instituting Rulemaking on the Commission's Own Motion to Improve Distribution Level Interconnection Rules and Regulations for Certain Classes of Electric Generators and Electric Storage Resources, Decision 12-09-018, Rulemaking 11-09-011, at 2 (Cal. P.U.C. Sept. 13, 2012).

250. *Id.* at 23.

251. *Id.* at 24-25.

252. *Id.* at 25.

253. *Id.* at 22.

254. *See generally Colorado's New Energy Economy a National Model*, COLO. CLEANTECH, http://www.cleantechhub.org/public-policy (last visited Oct. 22, 2013).

255. *Id.*

256. H.B. 10-1365, 67th Gen. Assemb., 2d Reg. Sess. (Colo. 2010) (codified at COLO. REV. STAT. § 40-3.2-201 (2012)).

consistent with the current and reasonably foreseeable requirements of specified federal and state laws, including the federal Clean Air Act.[257]

Following enactment of this legislation, the Colorado Public Utilities Commission (CPUC) and the state's two IOUs have been focused on the practical implementation of the utilities' ERPs, which has led to numerous CPUC dockets related to the retirement of certain coal-fired generation, repowering of certain generating facilities with natural gas, construction of new natural gas-fired generating units, installation of emissions controls at coal-fired generating units that will remain in operation, and the conversion of certain generating units to synchronous condensers to support transmission system operations.

Another high profile "legacy" CPUC docket reached a final conclusion in 2013. In May 2009, PSCo and Tri-State Generation and Transmission Association, Inc. (Tri-State) filed joint applications for Certificates of Public Convenience and Necessity (CPCN) to construct the San Luis Valley–Calumet–Comanche Transmission Project.[258] The proposed project involved the construction of nearly 150 miles of 230 kV and 345 kV transmission lines in southern Colorado to improve system reliability, increase the capacity of the existing transmission system in the project area, and facilitate the export of energy from renewable resources in southern Colorado to load centers along Colorado's Front Range.[259] The proposed project was met with resistance from local landowners, which led to a hotly contested hearing before the CPUC in July 2010.[260]

On September 13, 2011, more than two years after the original CPCN applications were filed, the Commission issued its final order granting the utilities' CPCN applications.[261] This decision was promptly followed by the commencement of a judicial review action in state district court challenging the CPUC's CPCN decision.[262] Due to the extraordinary length of time taken by the CPCN process, it became apparent that PSCo's original justification for participating in the proposed transmission project may have changed due to subsequent changes in the company's renewable energy resource needs.[263] As a result, the parties agreed to stay the district court action pending CPUC review

257. COLO. REV. STAT. § 40-3.2-204(2)(b)(I), (2)(b)(IV) (2012).

258. Application at 1, Application of Tri-State Generation and Transmission Association, Inc. for a Certificate of Public Convenience and Necessity for the San Luis Valley-Calumet-Comanche Transmission Project, Docket No. 09A-324E (Colo. P.U.C. May 14, 2009).

259. *Id.* at 4.

260. Public Service Company of Colorado's Response to Trinchera Ranch's Third Motion to Reopen the Record at 9-14, Application of Tri-State, Transmission Association, Inc., and Public Service Company of Colorado for a Certificate of Public Convenience and Necessity for the San Luis Valley-Calumet-Comanche Transmission Project, Docket Nos. 09A-324E, 09A-325E (Colo. P.U.C. May 18, 2011).

261. Public Service Company of Colorado's and Tri-State Generation and Transmission Association, Inc.'s Concurrence with Motion for Clarification at 1, Application of Tri-State, Transmission Association, Inc., and Public Service Company of Colorado, Docket Nos. 09A-324E and 09A-325E (Colo. P.U.C. Oct. 7, 2011).

262. Blanca Ranch Holdings LLC v. Public Utils. Comm'n of Colo., Case No. 2010-CV-16, at 1 (Colo. Dist. Ct., Costilla Cnty. Mar. 6, 2012) (order granting motion to hold in abeyance).

263. *Id.*

of PSCo's 2011 Electric Resource Plan.[264] Based on the CPUC's decisions concerning PSCo's resource needs, on April 30, 2013, PSCo informed the district court that "it [was] ending its involvement in the [p]roject, and will not proceed with its construction."[265] Given that the originally proposed project was an integrated project designed to meet the needs of both PSCo and Tri-State, PSCo's decision to discontinue its participation in the project resulted in Tri-State also terminating its plans to pursue the project.[266] At this time, Tri-State is exploring alternative projects that will address its continuing system reliability needs in southern Colorado.[267]

In May 2011, the CPUC adopted new transmission planning rules requiring Colorado electric utilities to file biennial ten-year transmission plans beginning February 1, 2012, and biennial twenty-year conceptual transmission scenarios beginning February 1, 2014.[268] The purpose of the new rules was to "establish a process to coordinate the planning for additional electric transmission in Colorado" based on "the concept that planning should be done on a comprehensive, transparent, state-wide basis and should take into account the needs of all stakeholders."[269] Following a lengthy but expedited stakeholder outreach process, PSCo, BHE, and Tri-State filed their first 2012 Joint Ten-Year Transmission Plan on February 1, 2012 identifying therein each utility's proposed transmission projects, the methodology used to select such projects, and the utilities' consideration of alternative projects.[270] On December 13, 2012, the CPUC issued its decision accepting the utilities' joint plan as adequate for purposes of the rules and providing guidance for subsequent ten-year transmission plan filings.[271]

Finally, on June 5, 2013, Colorado Governor John Hickenlooper signed into law Senate Bill 13-252, which significantly changed electric resource standards applicable to cooperative electric associations.[272] Prior to this legislation, Colorado law required investor-owned electric utilities to meet 30% of their retail sales from renewable resources by 2020, and cooperative electric associations were required to supply 10% of their retail sales from renewable resources by the same deadline.[273] Senate Bill 13-252 continued this requirement for most Colorado cooperative electric associations; however, the legislation doubled the 2020 renewable energy requirement for those

264. Blanca Ranch Holdings, LLC v. Public Utils. Comm'n of Colo., Case No. 2011-CV-7089 (Colo. Dist. Ct., Denver Cnty. Mar. 12, 2012) (order granting motion to stay).

265. Public Service Company of Colorado's Notice That It Does Not Intend to Proceed to Construct the San Luis Valley Transmission Line, Case No. 10-CV-16, ¶ 5 (Colo. Dist. Ct., Costilla Cnty. Apr. 30, 2013).

266. *Tri-State to Consider Alternative Transmission Project in Southern Colorado*, POWERING THE WEST (Jan. 15, 2013), http://www.poweringthewest.org/2013/01/15/tri-state-to-consider-alternative-transmission-project-in-southern-colorado.

267. *Id.*

268. COLO. CODE REGS. § 723-3627(a), (e) (2013).

269. *Id.* § 723-3626.

270. 2012 Ten-Year Transmission Plan Narrative Summary at 3, Tri-State Generation and Transmission Association, Inc., Docket No. 12M-102E (Colo. P.U.C. July 2, 2012).

271. Black Hills Corporation Senate Bill 07-100 Designation of Energy Resource Zones and Transmission Expansion Plant, Decision No. R12-1431, No. 11M-872E (Colo. P.U.C. Dec. 13, 2012).

272. S. 13-252, 69th Gen. Assemb., 1st Reg. Sess. (Colo. 2013).

273. COLO. REV. STAT. § 40-2-124(1)(c) (2013).

cooperatives serving 100,000 or more meters.[274] The legislation also newly defined a "qualifying wholesale utility" as a generation and transmission (G&T) cooperative electric association that provides wholesale electric service directly to Colorado electric associations that are its members, a definition which describes only one entity in Colorado, Tri-State—and established a new renewable energy requirement of 20% by 2020 for such wholesale utilities.[275]

D. Idaho

On May 31, 2013, the Idaho Public Utilities Commission (IPUC) issued an order resolving Idaho Power Company's (IPC) Power Cost Adjustment (PCA) application.[276] The IPUC approved IPC's request for a $140.4 million increase in PCA rates, which represents the fourth largest PCA on record in Idaho.[277] The approved rate increase represented a one-year average increase for residential customers of 12.5% and an overall average rate increase of 15.3% over all rate classes.[278] The IPUC addressed two significant issues in Order No. 32831.[279] First, the IPUC addressed the timing of the PCA recovery and weighed the benefits of rate mitigation versus the risk of rate pancaking.[280] Second, the IPUC addressed the issue of whether IPC should be required to include transmission revenues in addition to transmission costs in the calculation of the PCA.[281] Each of these issues is summarized individually below.

1. Rate Mitigation v. Rate Pancaking

The first major issue addressed before the IPUC in Order No. 32821 was the timing of the PCA recovery.[282] In its initial application, IPC requested IPUC approval of PCA rate recovery over a single year or over a two-year period in order to mitigate the large rate increase to customers.[283] The IPUC received public comments on this issue from numerous parties as well as alternative rate mitigation proposals from IPUC Staff, Industrial Customers of Idaho Power (ICIP), and the United States Department of Energy (DOE).[284] The parties were generally concerned with the customer impact of the large PCA rate increase and advocated for various proposals to spread the recovery over two or three years.[285] The issue of the timing of the PCA rate recovery centered on the risk that deferral of recovery would create rate pancaking in the future if additional rate

274. *Id.* § 40-2-124(1)(c)(V.5).

275. *Id.* § 40-2-124(8).

276. Application of Idaho Power Company for Authority to Implement Power Cost Adjustment Rates, Order No. 32821, Case No. IPC-E-13-10 (Idaho P.U.C. May 31, 2013) [hereinafter Order No. 32821].

277. Press Release, Idaho Pub. Util. Comm'n, Fourth Largest PCA on Record Becomes Effective June 1 (May 31, 2013), *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1310/staff/20130531PRESS%20RELEASE.PDF.

278. *Id.*

279. Order No. 32821, *supra* note 276, at 1-2.

280. *Id.* at 5-10.

281. *Id.* at 1.

282. *Id.* at 10.

283. *Id.* at 1.

284. *Id.* at 5-8.

285. *Id.* at 6-9.

increases become necessary in subsequent years.[286] The parties and the IPUC compared this rate pancaking risk against the desirability of mitigating the rate impact of the large PCA rate increase.[287]

Ultimately the IPUC authorized IPC to recover the PCA increase under the historically used single-year recovery mechanism.[288] In authorizing the single-year recovery, the IPUC noted:

> We are sympathetic to the request to spread the authorized rate increase over time, and we understand that allowing full recovery in one year will have an immediate, negative impact on all customers, some more than others. Our concern for creating the risk of compounding or "pancaking" rate increases in the future overshadows the impact we know will be felt this year. Forecasts for water are, at best, uncertain. Given this, we find it is too risky and potentially could compound "rate shock" for customers to spread this year's PCA recovery across multiple future years.[289]

As a result, IPC's customers will pay the full PCA recovery over a single year in order to avoid the possibility of even greater rate impacts in the future.[290]

2. Transmission Costs and Revenue

On April 23, 2013, the IPUC, through Order No. 32796, invited parties to the PCA proceeding to comment on the issue of whether IPC's PCA calculation should include both transmission expenses and revenues or transmission expenses alone.[291] IPUC Staff, ICIP, and IPC commented on this issue with IPUC Staff and ICIP advocating for inclusion of transmission revenues to prevent a regulatory mismatch.[292] IPC argued that transmission revenues should not be included in the PCA calculation as "there is no direct relationship between third-party transmission wheeling revenues and the [c]ompany's power supply expenses."[293] IPC also argued that including transmission revenue in the PCA calculation would be practically difficult as IPC's current revenue requirement does not contain an explicit transmission wheeling revenue component and thus there would be no base level of transmission wheeling revenue for deviation calculations.[294]

The IPUC found that a regulatory mismatch exists as a result of the use of only transmission expenses and not revenues in the PCA calculation, noting that:

> Under current practice, the Company's ratepayers are responsible for transmission expense differences each year through the PCA, but they do not receive the benefit of changes in transmission revenues unless and until a rate case occurs. We find it reasonable for the Company to include both transmission revenue and expense differences when calculating future PCAs.[295]

286. *Id.* at 9.
287. *Id.* at 7-9.
288. *Id.* at 10.
289. *Id.*
290. *Id.*
291. *Id.* at 1, 11-12.
292. *Id.* at 12-13.
293. *Id.* at 13.
294. *Id.*
295. *Id.*

The IPUC went on to find that a base level of transmission revenue is required in order to be included in future PCAs and as a result, IPC is now required to establish a base level of third-party transmission revenues in its next rate case in order for future deviations to be tracked.[296]

E. New Mexico

In 2009, the New Mexico legislature amended the Public Utility Act (PUA) to define a "future test period" for electric rate case proceedings before the New Mexico Public Regulation Commission (NMPRC).[297] Section 62-3-3(P) states: "'future test period' means a twelve-month period beginning no later than the date a proposed rate change is expected to take effect."[298] Section 62-6-14(D) states:

> The commission [NMPRC] shall set rates based on a test period that the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a future test period is proposed, the commission shall give due consideration that the future test period may best reflect those conditions.[299]

Subsequent to the passage of the statutes, two separate proceedings were filed at the NMPRC that requested that future test periods be used to determine their requested rates: Case No. 10-00086-UT was filed by the Public Service Company of New Mexico (PNM),[300] and Case No. 10-00395-UT by Southwestern Public Service Company (SPS).[301]

On December 30, 2010, SPS filed its rate case using a future test period as authorized by NMSA 1978, section 62-6-14(D).[302] The SPS Rate Case application anticipated using a future test period of (budgeted 2011 dollar amounts, with some adjustment to reflect certain events scheduled to occur in 2012).[303]

Following the filing of extensive testimony, lengthy discovery, and months of negotiations, SPS, Staff of the NMPRC's Utility Division, the Attorney General of New Mexico, Western Resource Advocates, the Coalition for Clean Affordable Energy, and Occidental Permian Ltd. entered into an Uncontested Comprehensive Stipulation.[304] The Hearing Examiner's Amended Certification

296. *Id.*

297. N.M. STAT. ANN. § 62-3-3(P) (2013).

298. *Id.*

299. *Id.* § 62-6-14(D).

300. Application of Public Service Company of New Mexico for a Revision of its Retail Electric Rates, Case No. 10-00086-UT (N.M. P.R.C. Mar. 31, 2010) (originally filed as Motion by Public Service Company of New Mexico Asking for Variances from NMPRC Rule 530 and a Protective Order Regarding its 2010 Rate Case).

301. Southwestern Public Service Company's Application for Revision of Its Retail Rates Under Advice Notice No. 235, Case No. 10-00395-UT (N.M. P.R.C. Dec. 28, 2010).

302. *Id.*

303. *Id.* at 5.

304. Uncontested Comprehensive Stipulation, Southwestern Public Service Company's Application for Revision of Its Retail Rates Under Advice Notice No. 235, Case No. 10-00395-UT (N.M. P.R.C. Docket Sept. 12, 2011).

of Stipulation adopting the *Uncontested Comprehensive Stipulation* was "adopted, approved[,] and accepted" by the NMPRC on December 28, 2011.[305]
On February 8, 2012, the Commission's utility Staff, PNM, and SPS filed a "Joint Petition to Initiate Rulemaking" with a proposed rule.[306] The joint petition attached a proposed rule, 17.1.2 NMAC entitled "Future Test Year Period Filing Requirements in support of Rate Schedules for Investor-Owned Utilities" (Proposed Rule).[307] "The purpose of the Proposed Rule is to define and specify the different or additional minimum data requirements to be filed in support of tendered rate schedules based on a future test year period that is not provided for in 17.9.530, 17.10.630, 17.12.730, and 17.13.930 NMAC (Data Rules)."[308] The reasoning behind the changes is that a future test year period "requires additional, and sometimes different, data requirements from those contained in the Data Rules in order to allow Staff and interested parties to properly analyze the utility's rate filing."[309] The final rule and a revised rule were ultimately adopted in Case No. 12-00029-UT.[310]

A joint motion for rehearing was requested by NMPRC Staff, PNM, SPS, New Mexico Gas Company (NMGC) and the AG.[311] On January 23, 2013, the NMPRC re-opened the docket for the purpose of adopting revisions to the proposed rules (without a hearing) that streamlined ratemaking proceedings and clarified that a utility must provide notice of revisions to the utility's original filing if the initial rate application's revenue surplus or deficiency increases or decreases by 5% or more, due to changes or errors and to seek Commission approval if the utility seeks to modify its initial application by more than 5%, up or down.[312] The docket was closed following the issuance of the order.[313]

F. Nevada

1. SB 123 Revises Provision Relating to Energy

Senate Bill 123 requires electric utilities in highly populated counties to file with the Public Utilities Commission of Nevada (PUCN) a comprehensive plan for emission reduction from coal-fired electric generating plants and for the replacement of such plants with increased capacity from renewable energy facilities and other electric generating plants.[314]

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305. Southwestern Public Service Company's Application for Revision of Its Retail Rates Under Advice Notice No. 235, Case No. 10-00395-UT (N.M. P.R.C. Dec. 28, 2011).

306. Joint Petition to Initiate Rulemaking, Adoption of a Proposed Rule Governing Public Utility Rate Applications Based on a Future Test Period, Docket No. 12-00029-UT (N.M. P.R.C. Feb. 8, 2012).

307. *Id.* exhibit A.

308. *Id.* at 3.

309. *Id.*

310. Proposed Rule Governing Public Utility Rate Applications Based on a Future Test Period, 30 P.U.R. 4th 547 (N.M. P.R.C. Nov. 29, 2012) (final order promulgating rule).

311. Joint Motion for Rehearing, Adoption of a Proposed Rule Governing Public Utility Rate Applications Based on a Future Test Period, Docket No. 12-00029-UT (N.M. P.R.C. Jan. 11, 2013).

312. Adoption of a Proposed Rule Governing Public Utility Rate Applications Based on a Future Test Period, No. 12-00029-UT, at 4 (N.M. P.R.C. Jan. 23, 2013).

313. *Id.* at 5.

314. S. 123, 2013 Leg., 77th Sess. (Nev. 2013).

The measure prescribes minimum requirements for emission reduction and capacity replacement, including: 1) the incremental retirement or elimination of coal-fired electric generating capacity; 2) "the construction or acquisition of, or contracting for, 350 [MW] of electric generating capacity from renewable energy facilities; and 3) the construction or acquisition of 550 [MW] of electric capacity from other electric generating plants," including without limitation.[315]

The measure provides for "the recovery of certain costs incurred by an electric utility in carrying out an emissions reduction and capacity replacement plan" in an amount that reflects a return on the electric utility's investment in the facility, depreciation in the facility, and the cost of operating and maintaining the facility.[316]

The PUCN shall review the utility's emission reduction and capacity plan or an amendment to the plan.[317] The PUCN may recommend a modification to the plan or amendment.[318] The utility has an opportunity to accept the modification or withdraw the proposed plan.[319] The Commission must consider the following when reviewing plans submitted pursuant to the statute: implementation costs to the utility's customers, economic benefits to the state, potential job creation, and value to the utility's customers.[320]

2. AB 428 Revises Provisions Relating to Energy

Assembly Bill 428 makes changes to the renewable energy incentive programs by placing statewide limits on the incentives paid for the solar, wind, and water programs.[321] The measure establishes a statewide capacity floor and requires the PUCN to revise incentive levels for the Solar Energy Incentive Programs.[322] "The [PUCN] shall set incentive levels and schedules, with a goal of approving solar energy systems totaling at least 250,000 [kW] of capacity" in Nevada from July 1, 2010, to December 31, 2021.[323] The incentive levels and capacity limitations for participation in the program must, at a minimum, distinguish among residential, non-residential, and low-income properties.[324] Incentives for the program are made performance-based and require the participant to prove that the system has been installed and energized before receiving an incentive payment.[325]

The measure also requires the PUCN to establish categories and capacity limits for the wind and water demonstration programs.[326] The bill limits the total amount paid to program participants and limits the maximum nameplate capacity

315. *Id.* at 1.
316. *Id.* at 1-5.
317. *Id.* at 17.
318. *Id.* at 17-18.
319. *Id.* at 2, 6.
320. *Id.* at 17.
321. H.R. 428, 2013 Leg., 77th Sess. (Nev. 2013).
322. *Id.* at 1, 3-4.
323. *Id.* at 3.
324. *Id.* at 8.
325. *Id.* at 1.
326. *Id.* at 10, 14.

to 500 kW.[327] The wind program incentive is based on performance and the amount of energy generated from the system.[328]

The bill requires electric utilities to establish a Lower Income Solar Energy Pilot Program for the purposes of installing distributive generation systems with a cumulative capacity with at least 1 MW prior to January 1, 2017.[329] This program provides for aggregate net metering for low-income housing residents and requires the PUCN to adopt regulation for participation in the program.[330]

G. Montana

In Montana, there have been several significant decisions regarding Qualifying Facility (QF) contracts. First, on September 13, 2011, the Montana Public Service Commission (MPSC) issued an order rejecting a request for a declaratory ruling regarding curtailment of purchases from QFs.[331] NorthWestern Energy (NorthWestern) filed a petition seeking a declaratory ruling that the curtailment language it proposed to include in new QF contracts was consistent with state and federal administrative rules.[332] NorthWestern proposed that the law permitted it to curtail purchases from a QF during “light load” hours.[333] The MPSC held that the proposed language was not authorized, and thus, NorthWestern was prohibited from demanding that new QFs accept such language as a condition to contracting with the utility.[334]

The next two significant QF decisions from the MPSC dealt with setting the avoided cost-based standard offer rates to be paid to those QFs that met the size limit for the standard offer rate. First, in October 2011, the MPSC set the total standard offer rate (capacity and energy) that NorthWestern would have to pay a QF and eliminated another wind only rate that had been established in a previous order because it found that the rate was no longer justified.[335] Next, in December 2012, the MPSC issued another order further reducing the standard offer rate for QFs selling to NorthWestern.[336] The MPSC also directed NorthWestern to remove a 50 MW installed capacity limit from its tariff.[337] This limit had been established by a previous MPSC order which permitted the utility to refuse to purchase energy from new QFs at the standard offer rates if it

327. *Id.* at 11, 14.

328. *Id.* at 11.

329. *Id.* at 16.

330. *Id.*

331. Petition of NorthWestern Energy for a Declaratory Ruling on the Applicability of 18 C.F.R § 292.304(f) and ARM § 38.5.1903(1) to Contracts with Qualifying Facilities, Order No. 7172, Docket No. D2011.7.57 (Mont. P.S.C. Sept. 13, 2011).

332. *Id.* ¶ 1.

333. *Id.* ¶ 5.

334. *Id.* ¶ 12.

335. NorthWestern Energy’s Application for Approval of Avoided Cost Tariff for New Qualifying Facilities, Order No. 7108e, Docket No. D2010.7.77, ¶¶ 51, 77 (Mont. P.S.C. Oct. 19, 2011).

336. NorthWestern Energy’s Application for Approval of Avoided Cost Tariff for New Qualifying Facilities, Order No. 7199d, Docket No. D2012.1.3, ¶ 76 (Mont. P.S.C. Dec. 7, 2012) [hereinafter Order No. 7199d].

337. *Id.*

already had 50 MW of purchased capacity coming from QFs.[338] NorthWestern requested that the MPSC reconsider this decision, which the MPSC denied in December 2012.[339] NorthWestern then appealed the MPSC's order to the First Judicial District Court of Montana in January 2013.[340] Following the filing of the appeal, NorthWestern requested that the MPSC stay its decision to eliminate the 50 MW cap pending the outcome of the appeal as NorthWestern argued that adding additional QF wind resources would increase portfolio costs and impose possible reliability concerns.[341] After a hearing, the MPSC granted NorthWestern's request for a stay.[342] As of June 30, 2013, the district court appeal is still pending.

Finally, in May 2013, after Montana's Governor vetoed House Bill 188, a bill that would have reduced the standard offer size limit for purchases from QFs from 10 MW to 3 MW,[343] the MPSC initiated a rulemaking proceeding to reduce the size limit from 10 MW to 100 kW, the minimum threshold established by the FERC.[344] The MPSC held a hearing on the rulemaking, but has yet to issue a decision on the proposed rule.

The MPSC also issued a significant decision regarding its jurisdiction over a public utility.[345] In December 2011, the MPSC held that it had jurisdiction over the sale and transfer of stock of a parent company that did not operate in Montana and approved the sale.[346] Park Water, which is a California public utility regulated by the California Public Utilities Commission, owned Mountain Water, a public utility regulated by the MPSC.[347] The owners of Park Water intended to sell their stock in Park Water.[348] The MPSC reasoned that it had jurisdiction over the California utility's proposed sale because of its power to regulate a Montana utility wholly-owned by a California utility.[349]

The MPSC also issued four significant decisions regarding the largest utility in the state, NorthWestern:

338. NorthWestern Energy's Applications for Approval of Avoided Cost Compliance Filing, Order No. 6501f, Docket No. D2003.7.86, ¶ 193 (Mont. P.S.C. Dec. 19, 2006).

339. Order No. 7199d, *supra* note 336 (denying the application due to lapse in time for Commission to act as established by administrative rules).

340. Petition for Judicial Review, NorthWestern Energy, Docket No. D2012.1.3 (Mont. Dist. Ct., Jan. 18, 2013).

341. NorthWestern Energy's Motion for Reconsideration, Stay, and Clarification of Portions of Final Order No. 7199d at 6-7, NorthWestern Energy's Application for Approval of Avoided Cost Tariff for New Qualifying Facilities, Docket No. D2012.1.3 (Mont. P.S.C. Dec. 7, 2012).

342. NorthWestern Energy's Application for Approval of Avoided Cost Tariff for New Qualifying Facilities, Order No. 7199e, Docket No. D2012.1.3, ¶ 55 (Mont. P.S.C. Apr. 2, 2012).

343. H.R. 188, 63th Legis., Reg. Sess. § 1(3)(b)(i)-(ii) (Mont. 2013).

344. Hearing Notice, Amendment of ARM 38.5.1902 Pertaining to Qualifying Facilities, Notice No. 38-5-218, ¶ 3 (Mont. P.S.C. May 23, 2013).

345. Consolidated Petition by Mountain Water Company for Declaratory Rulings and Application for Approval of Sale and Transfer of Stock, Order No. 7149d, Docket No. D2011.1.8, ¶ 51 (Mont. P.S.C. Dec. 14, 2011).

346. *Id.* ¶ 28.

347. *Id.* ¶¶ 1, 8, 51.

348. *Id.* ¶ 11.

349. *Id.* ¶ 51.

On February 16, 2012, the MPSC approved NorthWestern's application to purchase and rate base a 40 MW wind farm.[350] The MPSC found that the request to rate base Spion Kop wind project was in the public interest and that it would contribute to just and reasonable rates over the long-term for NorthWestern's customers.[351]

Then, in November 2012, the MPSC approved NorthWestern's application to include Battle Creek natural gas production and gathering properties in its natural gas rate base.[352] The Battle Creek facilities consist of 165 proven production wells, which will provide approximately 2.5% of NorthWestern's annual natural gas supply needs.[353]

H. Oregon

1. Pacificorp General Rate Case

On December 20, 2012, the Oregon Public Utility Commission (OPUC) issued Order No. 12-493, adopting a partial stipulation among the parties and resolving three disputed issues.[354] The three disputed issues resolved by the OPUC were:

a. Mona-to-Oquirrh Transmission Line

The Mona-to-Oquirrh transmission project is a new high-voltage transmission line with two substations in Utah.[355] Pacific Power sought approval to make a separate advice filing for the Oregon allocated portion of its investment in the project when it goes into service mid-way through the test year.[356] The Oregon allocated investment for the project is $12.6 million.[357] Over the objections of the Industrial Customers of Northwest Utilities (ICNU), Citizens Utility Board (CUB), and OPUC Staff, the OPUC granted Pacific Power's request for a rider with conditions.[358]

b. Power Cost Adjustment Mechanism

The OPUC addressed Pacific Power's request to implement a Power Cost Adjustment Mechanism (PCAM).[359] Pacific Power argued that its proposed PCAM was necessary in order to address under-recovery of net power costs (NPC), largely caused by the renewable portfolio standard implemented by SB 838.[360] Pacific Power requested a PCAM "without deadbands, earning bands,

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350. Application of NorthWestern Energy for Approval to Purchase and Operate the Spion Kop Wind Project, Order No. 71591, Docket No. D2011.5.41, ¶ 92 (Mont. P.S.C. Feb. 16, 2012).

351. *Id.* ¶ 130.

352. NorthWestern Energy's Application to Place the Battle Creek Natural Gas Production Resources in Rate Base, Order No. 7210b, Docket No. D2012.3.25, ¶ 2 (Mont. P.S.C. Nov. 16, 2012).

353. *Id.* ¶ 14 & n.1.

354. Pacificorp, Order No. 12-493, No. UE 246, 2012 WL 6644237 (Or. P.U.C. Dec. 20, 2012).

355. *Id.* at *4.

356. *Id.*

357. *Id.*

358. *Id.* at *4, *6.

359. *Id.* at *8-17.

360. *Id.* at *9.

sharing percentages, or any other feature that would deprive the utility of dollar-for-dollar recovery of any under-recovery of NPC."[361]

The OPUC adopted a PCAM for Pacific Power that included a deadband, a sharing mechanism, an earnings test, an amortization cap, and excluded application of the PCAM to direct access customers.[362]

c. Investment in Thermal Generation Plants

In this docket, Pacific Power sought recovery of the Oregon allocated portion (approximately $170 million) of the total $661 million of capital investments for emission control equipment at seven coal-fueled generation units owned by Pacific Power.[363] These emission controls were currently operating at the time of the request, but the costs had not been considered in a rate case.[364]

The OPUC analyzed Pacific Power's request under the OPUC's prudence standard and found deficiencies in Pacific Power's justifications for some plant upgrades as well as deficiencies in Pacific Power's decision making process related to said plant upgrades.[365] The OPUC ultimately disallowed 10% of Pacific Power's $170 million Oregon allocated request for a total disallowance of $17 million.[366]

I. Texas

The Electric Reliability Council of Texas (ERCOT) region includes the entire state except the Panhandle and parts of east Texas and far west Texas near El Paso that are in interstate power regions (e.g., the Southwest Power Pool (SPP)).[367] Because ERCOT is wholly intrastate, the Texas Legislature and the Public Utility Commission of Texas (PUCT) regulate both ERCOT's wholesale and retail electric markets.[368]

In response to ERCOT forecasts that the reserve margin in 2014 and beyond would fall below the 13.75% target reserve margin set by ERCOT's Board of Directors, the PUCT began investigating and addressing the factors causing generation development to lag behind expected growth in electricity demand.[369] Describing the resource adequacy issue as its top priority, the PUCT took a number of steps to address it, such as raising the system-wide offer cap from $3,000 per MWh to $4,500 per MWh, effective August 2012, and $9,000 per MWh in 2015.[370] The PUCT is considering additional steps it might take.

361. *Id.* at *7.

362. *Id.* at *12-13.

363. *Id.* at *14.

364. *Id.*

365. *Id.* at *27.

366. *Id.*

367. *Electric Reliability Council of Texas*, TEX. OFF. PUB. UTIL. COUNS., http://www.opuc.texas.gov/ERCOT.html (last visited Oct. 9, 2013).

368. *Id.*

369. PUB. UTIL. COMM'N OF TEX., SCOPE OF COMPETITION IN ELECTRIC MARKETS IN TEXAS – REPORT TO THE 83RD TEXAS LEGISLATURE 1 (2013) [hereinafter PUCT SCOPE OF COMPETITION], *available at* http://www.puc.texas.gov/industry/electric/reports/scope/Default.aspx.

370. *Id.* at 1, 5-6.

In October 2012, the PUCT amended Rule 25.181 regarding energy efficiency to add an evaluation, measurement, and verification framework; revise cost recovery for energy efficiency; and increase demand reduction goals.[371]

In March 2012, the PUCT adopted changes to Rule 25.192 and 25.501 that treat energy used to charge an electric energy storage facility as a wholesale transaction and apply to storage load the nodal price, instead of applying the zonal price to end-use consumption.[372]

In May 2012, the PUCT amended Rule 25.361 to authorize ERCOT to conduct pilot projects and to grant temporary exceptions from ERCOT rules as necessary to effectuate the purposes of the pilot projects.[373] ERCOT has been evaluating three pilot projects: thirty-minute emergency response service (ERS), fast responding regulation service, and weather-sensitive ERS.[374]

In May 2012, the PUCT amended Rules 25.211, relating to interconnection of DG, and 25.217, relating to distributed renewable generation (DRG).[375] Among other things the PUCT interpreted 2011 legislation, which defines a DRG owner to include retail electric customers who contract with third parties and states that DRG owners need not register with or be certified by the PUCT for purposes of DRG, to apply statewide.[376]

In October 2011, the PUCT modified its rules to increase the benefits and functionality of the advanced metering system being deployed by transmission and distribution utilities.[377]

In October 2012, the PUCT approved with conditions the application of Entergy Texas, Inc. for approval to join and to transfer operational control of its system to the Midwest Independent Transmission System Operator (MISO).[378]

In the 2013 regular session, the legislature continued the PUCT's existence until the next sunset review of the agency in 2023.[379] Legislation adopted in 2013 made few changes regarding the PUCT's regulation of the electric industry. The PUCT was, however, given express authority under limited circumstances to issue a cease and desist order without a hearing.[380]

J. Washington

1. Avista Corporation

On December 26, 2012, the Washington Utilities and Transportation Commission (WUTC) approved a multi-party settlement of a rate case for the

371. Rulemaking Proceeding to Amend Energy Efficiency Rules, Project No. 39674 (Tex. P.U.C. Oct. 17, 2012).

372. PUCT SCOPE OF COMPETITION, *supra* note 369, at 10-11.

373. *Id.* at 11.

374. *Pilot Projects*, ELECTRIC RELIABILITY COUNCIL TEX., http://www.ercot.com/mktrules/pilots/ (last visited Oct. 9, 2013).

375. PUCT SCOPE OF COMPETITION, *supra* note 369, at 11-12.

376. *Id.*

377. *Id.* at 8.

378. *Id.* at 13.

379. H.R. 1600, 2013 Leg., 83d Sess. § 1.01 (Tex. 2013) (amending TEX. UTIL. CODE § 12.005).

380. *Id.* § 1.06 (adding TEX. UTIL. CODE § 15.104).

gas and electric services of Avista Corporation (Avista Utilities).[381] The Avista Utilities had requested substantial attrition adjustments to its 2013 revenue requirements to compensate for the perceived inability of the traditional rate case process to account for high capital spending and slow sales volume growth.[382] The settlement provided for rate increases of $13.7 million for 2013 and $14 million for 2014[383] but does not include an explicit attrition adjustment.[384] The settlement also provided for a 9.8% ROE.[385]

381. Washington Utils. & Transp. Comm'n v. Avista Corp., Docket Nos. EU-120436, UG-120437, 303 P.U.R. 4th 113, 2012 WL 6725639 (Wash. U.T.C. Dec. 26, 2012).

382. *Id.* at *3.

383. *Id.* at *1.

384. *Id.* at *12.

385. *Id.* at *13.

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