

## **REPORT OF THE STATE COMMISSION PRACTICE COMMITTEE**

This report summarizes significant state developments in the utility industry from July 2017 through June 2018.\*

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## I. ARIZONA

A. *Effects of the 2017 Tax Cuts and Jobs Act (TCJA)*

The Tax Cuts and Jobs Act of 2017 (TCJA) reduced the federal corporate income tax rate from 35% to 21%, and the Arizona Corporation Commission (ACC) initially required all Arizona utilities to pass their tax savings on to their retail customers.<sup>1</sup> In February 2018, the ACC ordered the larger utilities in Arizona to track the TCJA's impacts by using regulatory assets and liabilities.<sup>2</sup> The utilities must also file within two months either (1) "an application for a tax expense adjustor mechanisms," (2) "an intent to file a rate case within" the next ninety days, or (3) "any such other application to address ratemaking implications of the" TCJA.<sup>3</sup>

Many of the major utilities chose option three. Some utilities filed to reduce their previously approved revenue requirements, reduce rates, and implement a one-time bill credit to pass to customers all tax savings accrued since January 1, 2018. Other utilities, such as Tucson Electric Power Company (TEP), will utilize a bill credit to refund their entire projected 2018 tax savings over the twelve-month period between May 2018 and April 2019.<sup>4</sup> In the following years, TEP will refund a percentage of tax savings and defer the remainder as a regulatory liability until its next rate case.<sup>5</sup>

B. *Competing Renewable Energy Plans*

Two Renewable Energy Initiatives are under consideration in Arizona—one is at the direction of the ACC and the other is a ballot initiative to amend the Arizona Constitution.<sup>6</sup> Arizona currently has a renewable energy standard created by the ACC that requires a minimum of 15% of electricity generation from eligible renewable resources by 2025.<sup>7</sup>

The Arizona Renewable Energy Standards Initiative (Ballot Measure) may appear as an initiated constitutional amendment on the November 2018 ballot.<sup>8</sup>

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1. Pub. L. No. 115-97, 131 Stat. 2054 (2017); *Commission Inquiry into Possible Modification of the Federal Income Tax Reform Rate Adjustment*, Decision No. 76595 (Feb. 26, 2018), available at <http://docket.images.azcc.gov/0000186358.pdf> [hereinafter Decision No. 76595].

2. Decision No. 76595, *supra* note 1, at 4.

3. *Id.*

4. TUCSON ELEC. POWER, TAX ADJUSTMENT CREDIT, <https://www.tep.com/tax-adjustment-credit/> (last visited Oct. 4, 2018).

5. *Id.*

6. ARIZ. CORP. COMM'N., ARIZONA'S ENERGY MODERNIZATION PLAN (Jan. 30, 2018), <https://www.azcc.gov/commissioners/atobin/letters/energyplan.asp> [hereinafter ENERGY MODERNIZATION PLAN]; *Arizona Proposition 127, Renewable Energy Standards Initiative*, BALLOTPEDIA (2018), [https://ballotpedia.org/Arizona\\_Proposition\\_127, Renewable\\_Energy\\_Standards\\_Initiative\\_\(2018\)](https://ballotpedia.org/Arizona_Proposition_127, Renewable_Energy_Standards_Initiative_(2018)).

7. Decision No. 69127, *In the Matter of the Proposed Rulemaking for the Renewable Energy Standard and Tariff Rules*, Docket No. RE-00000C-05-0030 (Ariz. Corp. Comm'n, Nov. 14, 2006).

8. *What's on my Ballot?*, Arizona 2018 General Election Publicity Pamphlet, 106 (Nov. 6, 2018), [https://azsos.gov/sites/default/files/2018\\_Publicity\\_Pamphlet\\_Final.pdf](https://azsos.gov/sites/default/files/2018_Publicity_Pamphlet_Final.pdf).

The Ballot Measure would require utilities that sell electricity in Arizona to acquire electricity from a certain percentage of renewable resources each year.<sup>9</sup> The amount would increase from 12% in 2020 to 50% in 2030 and in each year thereafter.<sup>10</sup> The Ballot Measure would define renewable energy to include solar, wind, biomass, and certain hydropower, geothermal, and landfill gas energies, and exclude nuclear power.<sup>11</sup> The Ballot Measure is currently being challenged in court by APS.<sup>12</sup>

Commissioner Tobin of the ACC has proposed an Arizona Energy Modernization Plan, which would be approved and implemented through a rulemaking at the ACC.<sup>13</sup> The Plan would require that, by 2050, 80% of Arizona's electricity generation must come from clean energy sources, including nuclear power, and it calls for the deployment of 3,000 megawatts of energy storage by 2030.<sup>14</sup> The Energy Modernization Plan includes policy proposals in areas of energy efficiency, resource planning, peak demand reduction, and electric vehicle infrastructure.<sup>15</sup> The Energy Modernization Plan would also require utilities to jointly procure sixty megawatts (MW) of electricity from biomass generators.<sup>16</sup>

## II. CALIFORNIA

### A. California Wildfires

Following several wildfires that occurred in Southern California, the California Public Utilities Commission (CPUC) initiated a Rulemaking to develop (1) a statewide fire map identifying high fire threat areas within California, and (2) new fire safety rules that will apply within those high fire threat areas.<sup>17</sup>

The fire map was developed through a multi-step process involving peer and expert review, as well as public input.<sup>18</sup> The map delineates "the boundaries of a new statewide High Fire-Threat District" (HFTD) where stricter fire regulations apply.<sup>19</sup> The boundary of the HFTD is based on two maps: (1) the United States Forest Service (USFS) and California Department of Forestry and Fire Protec-

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9. *Id.* at 36.

10. *Id.* at 37.

11. *Id.* at 39.

12. Robert Walton, *APS-Backed Group Challenges 50% Renewables Ballot Measure in Court*, UTILITY DIVE (July 25, 2018), <https://www.utilitydive.com/news/aps-backed-group-challenges-50-renewables-ballot-measure-in-court/528524/>.

13. ENERGY MODERNIZATION PLAN, *supra* note 6.

14. *Id.*

15. *Id.*

16. *Id.*

17. *Fire Safety Technical panel Workshop Report on Proposed Fire-Safety Regulations*, Rulemaking 15-05-006 at 2 (Cal. Pub. Util. Comm'n, Apr. 3, 2017); see also Baldwin et al., *Report of the State Commission Practice Committee*, 38 Energy L. J. 2 (2017), [https://www.eba-net.org/assets/1/6/State\\_Commission\\_Practice\\_Committee\\_\[FINAL\\_FOR\\_POSTING\]1.pdf](https://www.eba-net.org/assets/1/6/State_Commission_Practice_Committee_[FINAL_FOR_POSTING]1.pdf).

18. Decision 17-01-009, *Decision Adopting a Work Plan for the Development of Fire Map 2*, Rulemaking 15-05-006 at 15, 20, A-14-A-15 (Cal. Pub. Util. Comm'n, Jan 19, 2017) [hereinafter Decision 17-01-009].

19. *Id.* at 2.

tion's (CAL FIRE) joint map of Tree Mortality High Hazard Zones (Tree Mortality Map); and (2) the CPUC Fire-Threat Map.<sup>20</sup> The maps were approved January 19, 2018, and are available to the public.<sup>21</sup>

The HFTD has three fire-threat areas.<sup>22</sup> Zone 1 consists of "Tier 1 High Hazard Zones (HHZs)" on the Tree Mortality Map.<sup>23</sup> "Tier 1 HHZs are in direct proximity to communities, roads, and utility lines," and are "a direct threat to public safety."<sup>24</sup> Tier 2 consists of areas on the CPUC Fire-Threat Map "where there is an elevated risk" from wildfires associated with overhead utility facilities.<sup>25</sup> Tier 3 "consists of areas on the CPUC Fire-Threat Map where there is an extreme risk" from wildfires associated with overhead utility facilities.<sup>26</sup>

More stringent overhead line construction, inspection, and maintenance regulations apply within the HFTD.<sup>27</sup> On December 21, 2017, the CPUC issued its Decision Adopting Regulations to Enhance Fire Safety in the High Fire-Threat District.<sup>28</sup> The Decision approved revisions and additions to CPUC's rules, particularly General Order 95 (GO 95) related to overhead electric lines.<sup>29</sup> The new regulations include increased line and vegetation clearance requirements, shorter inspection cycles, and fire prevention planning.<sup>30</sup>

#### B. Physical Security and Emergency Preparedness

In 2015, the CPUC initiated a proceeding to establish regulations addressing physical security risks to California's electric supply facilities consistent with California Public Utilities Code section 364 (Phase I) and to establish standards for disaster and emergency preparedness plans for electrical corporations and regulated water companies consistent with Public Utilities Code section 768.6 (Phase II).<sup>31</sup> The rulemaking proceeding will also consider whether any new rules, standards, General Orders or modifications to other existing policies developed in Phase

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20. *Id.* at 39, 48, 86 p. mm. D.17-01-009 refers to the CPUC Fire-Threat Map as "the Shape B Map" and/or "the Shape C Map." D.16-05-036 refers to the CPUC Fire Threat Map as "Fire Map 2." *Id.*

21. Letter from Elizaveta Malashenko, Director of the Commission's Safety & Enforcement Division dated January 19, 2018, approving Advice Letters 5211-E and 3172-E filed January 5, 2018; CALIFORNIA PUBLIC UTILITIES COMMISSION, CPU FIREMAP, <https://ia.cpuc.ca.gov/firemap/> (last visited Oct. 12, 2018).

22. Decision 17-12-024, *Decision Adopting Regulations to Enhance Fire Safety in the High Fire-Threat District*, Rulemaking 15-05-006, at 145 (Cal. Pub. Util. Comm'n, Dec. 14, 2017) [hereinafter Decision 17-12-024].

23. *Id.*

24. *Id.*

25. *Id.* at 2.

26. *Id.*

27. Decision 17-12-024, *supra* note 22, at 39.

28. *Id.*

29. *Id.* at 2, 6.

30. *Id.* at 41, 50, 152, 154.

31. *Assigned Commissioner's Phase II Scoping Memo and Ruling*, Rulemaking 15-06-009, at 2 (Cal. Pub. Util. Comm'n, June 11, 2015) [hereinafter *Phase II Memo & Ruling*]; Cal. Pub. Util. Code § 218(a) (defining "Electrical corporation" to include "every corporation or person owning, controlling, operating, or managing any electric plant for compensation within [California]."). Publicly owned electric utilities are not electric corporations.

I, should apply to facilities owned by publicly owned utilities and rural electric cooperatives.<sup>32</sup>

Parties engaged in a series of workshops in 2017 and 2018, and circulated multiple Straw Proposals for establishing physical security rules for distribution facilities in California.<sup>33</sup> Several electric utilities filed their Straw Proposal with the CPUC on August 31, 2017.<sup>34</sup> Their Straw Proposal sets forth “Proposed Guidelines for Electric Utility Distribution System Security Assessments.”<sup>35</sup> The Guidelines would, if adopted by the CPUC as proposed, implement a risk management approach towards distribution system physical security, with appropriate consideration for resiliency, impact, and cost.<sup>36</sup> The guidelines would “not apply to facilities subject to the California Independent System Operator Corporation’s (CAISO) operational control and/or subject to North American Electric Reliability Corporation (NERC) Reliability Standard CIP-014-2 or its successors.”<sup>37</sup>

The CPUC’s Safety & Enforcement Division’s Risk Assessment & Safety Advisory Section issued an evaluation of the Straw Proposal and offered recommendations for consideration.<sup>38</sup> Parties submitted comments on these recommendations.<sup>39</sup> The CPUC has not issued a decision in Phase I as of August 2018.

Parties have also submitted briefs to the CPUC addressing whether the CPUC has the authority to impose new regulations addressing physical security of distribution systems on publicly owned electric utilities.<sup>40</sup> The CPUC has not issued a decision on this question as of August 2018.

On May 31, 2018, the CPUC opened Phase II of the proceeding, which addresses disaster and emergency preparedness plans for electrical corporations and regulated water companies.<sup>41</sup> The CPUC is expanding the rulemaking to provide guidance to regulated electric and water utilities on preparing to respond to disasters and other emergencies.<sup>42</sup> As with Phase I, the issues raised in the scoping memo will be addressed through a series of workshops, and will be followed by the submittal of a workshop report.<sup>43</sup> No hearings are anticipated.<sup>44</sup>

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32. *Id.* at 4-5.

33. *Joint Parties’ Filing of Updated Draft Straw Proposal for Physical Security Regulations*, Rulemaking 15-06-009, at 1-2 (Cal. Pub. Util. Comm’n, Aug. 31, 2017).

34. *Id.*

35. *Proposed Guidelines for Electric Utility Distribution System Security Assessments*, Rulemaking 15-06-009 (Cal. Pub. Util. Comm’n, Aug. 31, 2017).

36. *Id.* at 3-7.

37. *Id.* at 1.

38. *Safety & Enforcement Division’s RASA section evaluation of the Joint Utility Proposal and Recommendations for Consideration*, Rulemaking 15-06-009 (Cal. Pub. Util. Comm’n, Jan. 16, 2018), <http://docs.cpubc.ca.gov/PublishedDocs/Efile/G000/M204/K457/204457381.PDF>.

39. *Physical Security of Electric Infrastructure, Phase I*, CAL. PUB. UTILS. COMM’N, <http://www.cpubc.ca.gov/General.aspx?id=6442453847>.

40. *Id.*

41. *Phase II Memo & Ruling*, *supra* note 31, at 2.

42. *Id.*

43. *Id.* at 3.

44. *Id.*

### C. Amendments to GO 95

On June 7, 2018, the CPUC issued a “Decision Approving a Settlement Agreement that Amends Rule 18 of General Order 95.”<sup>45</sup> The Decision resulted in the amendment of Rule 18 of the CPUC’s GO 95, Rules for Overhead Electric Line Construction.<sup>46</sup> GO 95 contains rules for the design, construction, inspection, maintenance, repair, and replacement of overhead electric utility facilities and communications utility facilities (together, “overhead utility facilities”).<sup>47</sup> The purpose of GO 95 is to “ensure adequate service and secure safety to persons engaged in the construction, maintenance, operation or use of overhead lines and to the public in general.”<sup>48</sup> Rule 18 of GO 95 requires the correction of overhead utility facilities that pose a risk to safety or reliability, or otherwise do not comply with GO 95.<sup>49</sup> The amendments to Rule 18 reduce the maximum timeframe for correction of certain potential violations and authorize CPUC Staff to direct utilities to correct violations of GO 95 at specific locations earlier than the latest deadline allowed by Rule 18.<sup>50</sup>

The CPUC initiated this proceeding in response to a Petition filed by the CPUC’s Safety and Enforcement Division (SED) to eliminate Rule 18.<sup>51</sup> Parties conducted a series of settlement conferences culminating in a joint motion for the adoption of a settlement agreement, which was filed and served October 6, 2017.<sup>52</sup> Settling parties, including SED, and non-settling parties submitted comments on the settlement agreement proposing changes to Rule 18.<sup>53</sup> As noted above, the CPUC approved the settlement agreement and adopted the settlement agreement’s proposed amendments to Rule 18, with minor revisions.<sup>54</sup> These amendments were harmonized with the Fire Safety Regulations adopted in D.17-12-042.<sup>55</sup>

### D. Distributed Energy Resources (DERs)

The CPUC recently issued multiple decisions affecting DER procurement, in which the CPUC approved investment by investor-owned utilities (IOUs) in storage and electric vehicles (EV), and adopted programs intended to expand solar access in disadvantaged communities.

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45. Decision 18-05-042, *Decision Approving a Settlement Agreement that Amends Rule 18 of General Order 95*, Rulemaking 16-12-001 (Cal. Pub. Util. Comm’n, May 31, 2018) [hereinafter Decision 18-05-042].

46. *Id.*; General Order No. 95, *Rules for Overhead Electric Line Construction*, PUBLIC UTILITIES COMMISSION OF CALIFORNIA (May 2018), <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M217/K418/217418779.pdf> [hereinafter General Order No. 95].

47. General Order 95, *supra* note 46, at I-3.

48. *Id.*

49. *Id.* at I-9.

50. *Id.*; Decision 18-05-042, *supra* note 45, at 2.

51. Notice of Assignment, *Order Instituting Rulemaking to Consider Specified Amendments to Rule 18 of General Order 95*, Rulemaking 16-12-001 (Cal. Pub. Util. Comm’n, Dec. 9, 2016).

52. Joint Motion for Commission Adoption of Settlement Agreement, *Order Instituting Rulemaking to Consider Specified Amendments to Rule 18 of General Order 95*, Rulemaking 16-12-001, at 1-3 (Cal. Pub. Util. Comm’n, Oct. 6, 2017).

53. *Id.*

54. *See generally* Decision 18-05-042, *supra* note 45.

55. *Id.* at 38-39.

The CPUC affirmed California's continued commitment to DERs as viable alternatives to traditional electric procurement, particularly as the preferred alternative to building new gas plants to replace the lost generation from the San Onofre Nuclear Generating Station (SONGs) and gas-fired plants using once-through-cooling technology.<sup>56</sup> The CPUC ordered Southern California Edison (SCE) to, beginning in 2014, conduct a "Preferred Resources Pilot" to procure from DERs local capacity needed for reliability.<sup>57</sup> A proposed CPUC decision in March 2018 would have rejected SCE's procurement plan for 125 MW of energy storage projects, all of which were awarded contracts in 2016, but those contracts had been pending CPUC approval for almost eighteen months (A.16-11-002).<sup>58</sup> An "alternate decision," written by CPUC President Picker and adopted by a CPUC vote, rejected the prior decision's reasoning that those contracts were not in the ratepayers' best interests because they were not cost-effective.<sup>59</sup>

The CPUC approved the IOUs' plans to invest over \$750 million in EV infrastructure.<sup>60</sup> This new utility infrastructure spending will focus on creating the infrastructure to support charging stations particularly for heavy-duty vehicles, such as electric trucks and buses.<sup>61</sup> Previous spending plans have focused on passenger-vehicle charging infrastructure.<sup>62</sup>

Through the successor net energy metering (NEM) tariff proceeding, R.14-07-002, the CPUC adopted three new programs to promote solar in disadvantaged communities.<sup>63</sup> The first new program, the Disadvantaged Communities – Single-family Solar Homes (DAC-SASH) program, modeled after the existing Single-family Affordable Solar Homes (SASH) program, will provide up-front financial incentives towards the installation of solar systems for low-income homeowners.<sup>64</sup> The second program established is the Disadvantaged Communities – Green Tariff (DAC-Green Tariff) program which will provide a 20% bill discount to customers in disadvantaged communities as compared to the regular green-tariff program that allows IOU customers to opt-in to a higher proportion of renewable energy.<sup>65</sup> The third program established is the Community Solar Green Tariff program.<sup>66</sup> The goal of this program is to allow primarily low-income customers in disadvantaged communities to benefit from the development of solar generation projects located

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56. Alternate Proposed Decision, *Decision Approving The Results Of Southern California Edison Company's Second Preferred Resources Pilot Procurement*, Application 16-11-002, at 5-6, 11 (Cal. Pub. Util. Comm'n, May 30, 2018).

57. *Id.* at 2.

58. *Id.*

59. *Id.*

60. Decision 18-05-040, *Decision on the Transportation Electrification Standard Review Projects*, Applications 17-01-020, -021, -022, at 2 (Cal. Pub. Util. Comm'n, May 31, 2018).

61. *Id.*

62. *Id.*

63. Decision 18-06-027, *Alternate Decision Adopting Alternatives to promote Solar Distributed Generation in Disadvantaged Communities*, Rulemaking 14-07-002, at 2 (Cal. Pub. Util. Comm'n, June 21, 2018) [hereinafter Decision 18-06-027].

64. *Id.* at 2-3.

65. *Id.* at 3.

66. *Id.*



in or near their communities.<sup>67</sup> These communities will work with a local non-profit or local government “sponsor” to organize community interest and present siting locations to the utility; the sponsor can also receive an incentive for its efforts.<sup>68</sup>

#### *E. Rooftop Solar Mandate*

The CEC sets the state’s “Title 24” energy efficiency building standards for new residential homes and commercial buildings.<sup>69</sup> The CEC has adopted new residential building standards that will go into effect in 2020 that mandate rooftop solar (or an equivalent amount of community solar) for all new construction.<sup>70</sup> The CEC determined the additional costs related to installation of rooftop solar are cost-effective to the homeowner using the CEC’s life-cycle cost and time-dependent valuation (TDV) methods.<sup>71</sup>

#### *F. CAISO Regionalization*

The CAISO’s Western Energy Imbalance Market (EIM) launched in 2014, and is a real-time cross-border energy market.<sup>72</sup> The EIM now covers portions of the electric grid in eight states and one Canadian province.<sup>73</sup> Its market systems optimize the use of low-cost energy to balance supply and demand across a wide geographic area.<sup>74</sup> The EIM allows participants to buy and sell power in real-time and gives system operators visibility across neighboring grids.<sup>75</sup>

The Western EIM is governed by a governing body with five seats, with each member serving a three-year term.<sup>76</sup> A nominating committee made up of representatives from across the West and representing different industry sectors develops a list of candidates to recommend for appointment when openings arise after the initial term of the first governing body members.<sup>77</sup>

The CAISO launched the Western EIM on November 1, 2014 with its first participant, Oregon-based PacifiCorp.<sup>78</sup> NV Energy joined in 2015, Puget Sound Energy and APS joined in 2016, Portland General Electric on November 1, 2017, and Idaho Power and Powerex of Vancouver, British Columbia on April 4, 2018.<sup>79</sup>

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67. *Id.* at 3-4.

68. Decision 18-06-027, *supra* note 63, at 76-77.

69. For more information, see the “Docket Log” for 17-BSTD-02, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-BSTD-02>. Minimum system size varies by climate zone and square footage of the home. The decision does provide very limited exceptions to the mandatory solar requirement.

70. *Id.*

71. *Id.* at 4-5. The TDV method used by the CEC is not consistent with the cost effectiveness tests used by the CPUC for the IOUs’ energy efficiency programs.

72. *About*, WESTERN EIM, <https://www.westerneim.com/Pages/About/default.aspx> (last visited Oct. 16, 2018).

73. *Id.*

74. *Id.*

75. *Id.*

76. *Id.*

77. WESTERN EIM, *supra* note 72.

78. *Id.*

79. *Id.*

The CAISO expects new entities within California to join the EIM in 2019 and 2020.<sup>80</sup>

### III. DELEWARE

#### A. *New Transmission Infrastructure Development*

On February 14, 2018, Delaware's Governor, John Carney, signed legislation establishing parameters the Delaware Public Service Commission (DEPSC) must assess in determining whether to grant a certificate of public convenience and necessity for new electric transmission utilities.<sup>81</sup> The legislation also grants DEPSC the authority to revoke a certificate in the future for good cause.<sup>82</sup> The legislation provides any person or entity seeking to begin business as an electric transmission utility in Delaware must file for a certificate of public convenience and necessity.<sup>83</sup> In reviewing the application, the DEPSC can consider: (1) "whether PJM Interconnection LLC (PJM) has selected the applicant" to own the transmission facilities as part of PJM's developer qualification and competitive procurement program; and (2) the potential "impact of granting the certificate of public convenience and necessity" on Delaware's economy, the state's ratepayers, and on the public health, safety, and welfare.<sup>84</sup> The DEPSC must "act on an application a for certificate of public convenience and necessity within [ninety days] of the submission" of the application, unless extended for a period not to exceed an additional ninety days.<sup>85</sup> The DEPSC may, for good cause, "undertake to suspend or revoke a certificate of public convenience and necessity."<sup>86</sup>

#### B. *Offshore Wind*

On August 28, 2017, Governor Carney issued an Executive Order requiring a Working Group to convene no later than September 30, 2017, for the purpose of assessing offshore wind opportunities in Delaware.<sup>87</sup> The group is tasked with: (1) reviewing and recommending changes to the laws and regulations governing the development of offshore wind; (2) analyzing "*environmental benefits of developing offshore wind*;" (3) reviewing "economic opportunities presented by the offshore wind industry;" and (4) identifying of barriers to and opportunities for developing offshore wind in Delaware.<sup>88</sup>

The Working Group must report to the Governor no later than December 15, 2017, on: (1) relevant laws and regulations; (2) barriers to and opportunities for

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80. *Id.*

81. H. B. 127, 149th Gen. Assemb. (Del. 2018), <https://legis.delaware.gov/BillDetail?LegislationId=25630> [hereinafter HB-127].

82. *Id.* § 203E(e).

83. *Id.* § 203E(a).

84. *Id.* §§ 203E(b)(1)-(3).

85. *Id.* § 203E(c).

86. HB-127, *supra* note 81, § 203E(e).

87. Exec. Order No. 13 (Del. 2017), <https://governor.delaware.gov/wp-content/uploads/sites/24/2017/08/Executive-Order-Number-13.pdf>.

88. *Id.* at P 5.

facilitating offshore wind development; (2) strategies for “procuring offshore wind power to serve Delaware;” and (3) necessary “legislation including possible amendments to Delaware’s Renewable Energy Portfolio Standards Act.”<sup>89</sup> The Executive Order named the Division of Energy & Climate Change of the Department of Natural Resources the “lead agency staffing the Working Group,” and provided that the Working Group was to dissolve on June 30, 2018, “unless reconstituted by further Executive Order.”<sup>90</sup>

#### IV. DISTRICT OF COLUMBIA

##### A. *Reduction to Federal Corporate Income Tax Rate*

On January 23, 2018, the Public Service Commission of the District of Columbia (DC PSC) opened a proceeding to determine: (1) the impact of the Tax Cuts and Jobs Act (TCJA) on the current revenue requirements of Potomac Electric Power Company (Pepco) and Washington Gas Light Company (WGL), and (2) options for distributing to customers the reduction of each company’s revenue requirements through the existing distribution service rates.<sup>91</sup> The DC PSC’s Order “directs Pepco and WGL to track the impact” of the TCJA on their “revenue requirements beginning January 1, 2018,” and to “apply regulatory accounting, which includes the use of regulatory assets and liabilities, for all impacts” resulting from the TCJA.<sup>92</sup> The DC PSC intends to act in this proceeding based on the written record, “unless the parties identify material issues of fact that require a hearing.”<sup>93</sup>

##### B. *Competitive Electricity Auction*

On March 7, 2018, the DC PSC issued Order No. 19289, which provides that beginning June 1, 2018, the cost of electricity supply will decrease for District customers who purchase electricity through the default provider, referred to as Standard Offer Service (SOS).<sup>94</sup> SOS is the default electricity service for customers who have not chosen to purchase electricity from a licensed competitive electric provider, and the DC PSC has designated Pepco as the current SOS service provider.<sup>95</sup> Pepco purchases electricity for SOS customers through power supply contracts in an annual auction, and the lower electricity rates for District customers—a 5.3% average decrease for residential customers and a 4.3% average decrease for small commercial customers—are the result of a competitive auction for electricity supply held in December 2017 and January 2018.<sup>96</sup>

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89. *Id.* at P 6.

90. *Id.* at PP 7-8.

91. Order No. 19247, *In the Matter of the Impact of the Tax Cuts and Jobs Act of 2017 on the Existing Distribution Service Rates and Charges for Potomac Electric Power Company and Washington Gas Light Company*, Formal Case No. 1151, (D.C. Pub. Serv. Comm’n, Jan. 23, 2018).

92. *Id.* at P 7.

93. *Id.* at P 10.

94. Order No. 19289, *In the Matter of the Development and Designation of Standard Offer Service in the District of Columbia*, Formal Case No. 1017 (D.C. Pub. Serv. Comm’n, Mar. 7, 2018).

95. *Id.* at PP 1-2.

96. *Id.* at P 3.

## V. GEORGIA

A. *Georgia Power Company Plant Vogtle Nuclear Expansion*

On December 21, 2017, the Georgia Public Service Commission (Georgia PSC) voted to approve the costs incurred for the Plant Vogtle Nuclear Expansion during Georgia Power Company's (Georgia Power) Seventeenth semi-annual reporting period of January 1, 2017 through June 30, 2017.<sup>97</sup> The Georgia PSC also approved as reasonable the Company's revised cost forecast and schedule in support of Georgia Power's request to continue the project.<sup>98</sup> The Georgia PSC initially certified the Vogtle project in 2009, with a project configuration whereby Georgia Power entered a "fixed price" Engineering, Procurement and Construction Agreement (EPC Agreement) with Westinghouse Electric Company, LLC (Westinghouse) and other consortium members to design and construct the facility.<sup>99</sup> However, Westinghouse entered into Chapter 11 bankruptcy proceedings in March 2017 and was no longer able to perform under the EPC Agreement.<sup>100</sup> Georgia Power entered into Interim Assessment Agreements with Westinghouse to continue work on the Vogtle project during which time Georgia Power performed assessments to determine the best path forward for the nuclear project.<sup>101</sup>

On August 31, 2017, Georgia Power filed its Seventeenth Semi-Annual Monitoring Report as part of its on-going construction monitoring of the nuclear expansion pursuant to O.C.G.A. § 46-3A-7(b).<sup>102</sup> Georgia Power requested approval for continuing the project, with Georgia Power and affiliate Southern Nuclear Operating Company acting as the Project Manager overseeing the prime construction contractor, Bechtel Corporation.<sup>103</sup> Georgia Power submitted a revised capital cost estimate of \$8.8 billion for its 45.7% interest in the Vogtle project and expected commercial operation dates of November 2021 for Unit 3 and November 2022 for Unit 4.<sup>104</sup> Georgia Power cited a number of conditions regarding its request to continue the Vogtle project, such as the U.S. Congress extending the deadline for the Production Tax Credits, payment of a parent guaranty by Toshiba Corporation (the parent of Westinghouse), and additional loan guarantees being extended by the Department of Energy.<sup>105</sup>

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97. Order on the Seventeenth Semi-Annual Vogtle Construction Monitoring Report for the Period January 1, 2017 through June 30, 2017, Docket No. 29849 (Ga. Pub. Serv. Comm'n, Jan. 11, 2018) [hereinafter VCM 17 Order].

98. *Id.*

99. *Georgia Power Company's Seventeenth Semi-Annual Construction Monitoring Report, Request For Approval of the Expenditures Made Between January 1, 2017 and June 30, 2017, And Request for Approval of the Revised Project Cost Estimates and Construction Schedule Pursuant to O.C.G.A. § 46-3A-7(b)*, Docket No. 29849, at 24 (Ga. Pub. Serv. Comm'n, Aug. 31, 2017) [hereinafter VCM 17 Report].

100. *Id.* at 33-34.

101. *Id.*

102. VCM 17 Order, *supra* note 97, at 1.

103. *Id.* at 11.

104. *Id.* at 10.

105. *Id.* at 8.

During a special Administrative Session on December 21, 2017, the Georgia PSC verified and approved the \$542 million spent during the Seventeenth reporting period and ordered further that “Georgia Power shall move forward to complete construction of Vogtle Units 3 and 4,” subject to several conditions the Georgia PSC imposed on the Company.<sup>106</sup> In approving the Company’s revised cost and schedule forecast, the Georgia PSC ordered the cost forecast to be reduced by the amount of “the Toshiba Parent Guaranty” applied to Georgia Power’s construction work in progress balance, and noted that it has neither approved nor disapproved the recovery of any costs.<sup>107</sup> The VCM 17 Order further approved the new project structure as a self-build project.<sup>108</sup> The VCM 17 Order also provided Georgia Power would continue to bear the burden of proving any capital costs incurred over \$5.68 billion were prudent and the January 3, 2017 Stipulation remains in effect.<sup>109</sup> The VCM 17 Order also provided for reductions in the allowed return on equity collected under the Nuclear Construction Cost Recovery tariff and required Georgia Power to provide three \$25 refunds to customers no later than the third quarter of 2018 out of a portion of the proceeds received from the Toshiba Parent Guaranty.<sup>110</sup> The VCM 17 Order also identified when the Company may request inclusion of certain costs in rates for Units 3 and 4.<sup>111</sup>

On February 1, 2018, Georgia PSC denied a Petition for Rehearing and Reconsideration from Georgia Watch.<sup>112</sup> On February 12, 2018, intervenors Georgia Interfaith Power and Light and Partnership for Southern Equity filed a joint petition for judicial review of the VCM 17 Order, and on March 8, 2018 Georgia Watch also filed a petition for judicial review of the VCM 17 Order in the Fulton County Superior Court of Georgia.<sup>113</sup> The Superior Court consolidated the petitions for purposes of briefing and oral argument.<sup>114</sup> On April 27, 2018, Georgia Power filed a Motion to Dismiss, which is currently pending as of the date of this Report.<sup>115</sup>

On February 28, 2018, Georgia Power filed its Eighteenth Vogtle Construction Monitoring Report for the period July 1, 2017 through December 31, 2017 to request verification and approval of \$448 million incurred during the Reporting

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106. *Id.* at 17.

107. VCM 17 Order, *supra* note 97, at 17-18.

108. *Id.* at 18.

109. *Id.* at 18-19.

110. *Id.* at 19.

111. *Id.* at 18-19.

112. *Order Denying Petition for Rehearing and For Reconsideration*, Docket No. 29849 (Ga. Pub. Serv. Comm’n, Feb. 28, 2018).

113. *Petition for Judicial Review, Georgia Interfaith Power & Light et al. v. Georgia Pub. Serv. Comm’n*, Docket No. 2018CV301128 (Ga. Sup. Ct., Feb. 12, 2018); *Georgia Watch v. Georgia. Pub. Serv. Comm’n*, Docket No. 2018CV301252 (Ga. Sup. Ct., Apr. 10, 2018).

114. *See generally* Ga. Code Ann. § 9-11-42(a) (2018).

115. Georgia Power Company’s Motion to Dismiss the Petitions for Judicial Review Filed by Georgia Interfaith Power & Light, Partnership for Southern Equity, and Georgia Watch, *Ga. Interfaith Power & Light & Partnership for Southern Equity, Inc. v. the Georgia Pub. Serv. Comm’n*, Docket No. 2018CV301128, *Georgia Watch v. Ga. Pub. Serv. Comm’n*, Docket No. 2018CV301252 (Ga. Sup. Ct., Apr. 27, 2018).

Period, which is pending a final decision by the Georgia PSC on August 21, 2018.<sup>116</sup>

*B. Georgia Power Renewable Cost Benefit Framework*

Georgia Power negotiated over the course of several years with the Georgia PSC's staff and various intervenor groups to develop the terms and conditions of how to apply the Renewable Cost Benefit (RCB) Framework to value renewable energy purchases.<sup>117</sup>

In Georgia Power's 2016 Integrated Resource Plan (IRP) proceeding, the Georgia PSC approved stipulations requiring Georgia Power to utilize a modified RCB Framework to evaluate bids submitted in response to its Request for Proposals for the Renewable Energy Development Initiative (REDI) utility-scale and distributed generation projects.<sup>118</sup> The modified RCB Framework for REDI was "limited to the consideration of Avoided Energy and Deferred Generation Capacity cost components" with "appropriate transmission and distribution costs and benefits" considered on a case-by-case basis.<sup>119</sup> In addition, Georgia Power agreed, for information purposes only, to conduct an evaluation and file the results with the Georgia PSC, using the entire RCB Framework as filed by the Company, including Generation Remix, Support Capacity, and Bottom Out Adjustments cost components, to allow the Georgia PSC Staff and Independent Evaluator to gain familiarity with the RCB Framework.<sup>120</sup> Finally, the Georgia PSC required the Company and Public Interest Advocacy Staff to work together to "develop a process and recommendations" for a continued implementation of the RCB Framework and file their proposal within four months.<sup>121</sup>

On December 2, 2016, the Georgia PSC Staff filed a Joint Recommendation of the Staff and Georgia Power for the continued implementation of the RCB Framework.<sup>122</sup> The parties proposed adoption of the RCB Framework as amended in the Joint Recommendation.<sup>123</sup> The amended RCB Framework's components included: "Avoided Energy Costs, Deferred Generation Capacity Costs, Reduced Transmission Losses, and Reduced Distribution Losses" components as originally proposed by the Company.<sup>124</sup> In addition, the Framework included the following modified components: Generation Remix, Support Capacity – Regulation, Sup-

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116. *Georgia Power Company's Eighteenth Semi-Annual Construction Monitoring Report for Plant Vogtle Units 3 and 4*, Docket No. 29849 (Ga. Pub. Serv. Comm'n, Feb. 28, 2018); *Procedural and Scheduling Order*, Docket No. 29849 (Ga. Pub. Serv. Comm'n, Mar. 28, 2018).

117. Ga. Pub. Serv. Comm'n, 139<sup>th</sup> Annual Report, at 38 (2017).

118. *Order Adopting Stipulations*, Docket Nos. 40161, 40162 (Ga. Pub. Serv. Comm'n, Aug. 2, 2016) [hereinafter IRP Order].

119. *Id.* at p. 8(a).

120. *Id.* at p. 8(b).

121. *Id.* at p. 7.

122. *Joint Recommendation*, Docket No. 40161 (Ga. Pub. Serv. Comm'n, Dec. 2, 2016) [hereinafter *Joint Recommendation*].

123. *Id.*

124. *Id.* at p. 1.

port Capacity – Regulation and Forecast Error, and Deferred Transmission Investment.<sup>125</sup> “Bottom Out Costs, Ancillary Services (including reactive supply and voltage control), Distribution Operation Costs, Long Term Service Agreement Costs (e.g. ‘Starts-Based Maintenance Costs’), Target Reserve Margin Costs (‘Planning Reserve Margin Costs’), Program Administration Costs and Support Capacity – Ramping” components were all included in the Framework as placeholders only until a more robust methodology could be determined.<sup>126</sup> Fuel Hedging and Avoided Renewable Energy Credits were not included in the RCB Framework but the parties reserved the right to recommend future inclusion of these components.<sup>127</sup> “For purposes of compromise, the parties agree that the RCB Framework will not be used for the evaluation of behind the meter solar technologies.”<sup>128</sup> The Georgia PSC approved the Joint Recommendation on December 22, 2016.<sup>129</sup>

Georgia Power collaborated with the Georgia PSC’s Staff and various intervenor groups for several months to further resolve the application of the RCB Framework to “behind the meter” solar technologies.<sup>130</sup> “On May 25, 2017, Georgia Power filed for approval an Application to apply the RCB Framework to behind the meter programs, a revised Renewable and Nonrenewable Resources Tariff (RNR-9), and a request to adjust the REDI distributed generation (DG) schedule.”<sup>131</sup> Consistent with the agreed terms of the resulting Joint Recommendation, on June 6, 2017, the Georgia PSC approved application of the RCB Framework to “behind the meter” solar technologies, including its application to Georgia Power’s revised Renewable and Non-Renewable Rate Schedule.<sup>132</sup> During the past year, Georgia Power has been working to fully implement and apply the RCB Framework to the pricing for all of Georgia Power’s renewable resource programs to comply with the Georgia PSC’s orders.<sup>133</sup>

## VI. HAWAII

### A. *Reduction to Federal Corporate Income Tax Rate*

On January 26, 2018, the Hawaii Public Utilities Commission (HPUC) opened a new proceeding to investigate the impact of the TCJA on regulated utilities in Hawaii.<sup>134</sup> The HPUC’s Order directs public utilities in the state to begin

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125. *Id.* at p. 2.

126. *Id.* at p. 3.

127. Joint Recommendation, *supra* note 122, at p. 4.

128. *Id.* at 4.

129. *Order Approving Joint Recommendation Regarding the Renewable Cost Benefit Framework*, Docket No. 40161 (Ga. Pub. Serv. Comm’n, Dec. 22, 2016).

130. *Order Approving Georgia Power Company’s Request to Apply the Renewable Cost Benefit Framework to Behind the Meter Solar Technologies and to Adjust the Renewable Energy Development Initiative Distributed Generation Program Schedule*, Docket Nos. 40161, 16573 (Ga. Pub. Serv. Comm’n, June 7, 2017).

131. *Id.* at 1.

132. *Id.* at 3.

133. *Id.*

134. Order No. 35241, *Opening a Proceeding to Investigate the Impacts of the Tax Cuts and Jobs Act of 2017*, Docket No. 2018-0012 (Haw. Pub. Utils. Comm’n, Jan. 26, 2018).

tracking any savings incurred from lower tax rates, including “recognition of excess deferred income tax, as applicable.”<sup>135</sup> After reviewing the amount of tax savings for each applicable public utility, the HPUC intends to issue additional orders and make rate adjustments in separate proceedings to assure tax savings are passed on to customers.<sup>136</sup>

### B. *Green Initiatives*

On October 20, 2017, the HPUC issued a Decision and Order approving two new programs—the Smart Export program and the Controllable Customer Grid Supply (Controllable CGS) program—that will purportedly expand opportunities for customers to install rooftop solar and battery energy storage systems.<sup>137</sup>

The Smart Export program offers a new option for customers installing a rooftop photovoltaic (PV) system combined with a battery energy storage system. Under the new option, a customer’s energy storage system will recharge during the daytime with energy captured from their PV system.<sup>138</sup> The energy storage system will then power their home in the evening with an option to export electricity back to the grid in exchange for a bill credit.<sup>139</sup>

Under the new Controllable CGS program, participating customers can “install a solar PV-only system (no energy storage needed) that exports energy to the electric grid during the daytime,” and will “utilize advanced equipment that allows the electric utility to manage power from the [Controllable] CGS system.”<sup>140</sup> The Controllable CGS program is a successor to the current CGS program, and HPUC determined that “customers in the CGS program will continue to receive their current bill credit rate for the next five years.”<sup>141</sup> The HPUC is also allowing existing NEM customers to add “non-export” systems to their current systems “if they meet certain technical requirements,” which will allow such customers to “retain their status in the NEM program.”<sup>142</sup>

### C. *Updates to Regulatory Structure*

As Hawaii’s electric power industry transitions toward a more distributed model that incorporates increasing volumes of renewable generation, policy makers recently took two actions to update the existing regulatory structure. On April 18, 2018, the HPUC issued an order, opening a proceeding to investigate performance-based regulation for the Hawaiian Electric Companies.<sup>143</sup> Six days later,

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135. *Id.* at 6-7, Order no. 1.

136. *Id.* at 7, Order no. 3.

137. Order No. 34924, *Decision and Order*, Docket No. 2014-0192 (Haw. Pub. Utils. Comm’n, Oct. 20, 2017).

138. Press Release, *HPUC Expands Options for Customers to Install Rooftop Solar and Energy Storage*, HAWAII PUB. UTILS. COMM’N, (Oct. 20, 2017), <https://puc.hawaii.gov/wp-content/uploads/2017/10/Hawaii-PUC-Rooftop-Solar-and-Storage-Press-Release-10-20-17-FINAL.pdf>.

139. *Id.*

140. *Id.*

141. *Id.*

142. *Id.*

143. Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, Docket No. 2018-0088 (Haw. Pub. Utils. Comm’n, Apr. 18, 2018) [hereinafter Order No. 35411].



Governor Ige signed Act 5, which mandates that “electric utility rates [will] be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues.”<sup>144</sup> The HPUC intends to use a two-phase process to facilitate its investigation and comply with the legislative mandate.<sup>145</sup> The first phase, which the HPUC intends to complete in nine months, will evaluate what incentive mechanisms and regulatory components must be modified to better align the Hawaiian Electric Companies’ behavior with the public interest.<sup>146</sup> The second phase, which is expected to take 12 months, will implement revisions that were identified and further developed in Phase 1.<sup>147</sup>

## VII. ILLINOIS

### A. *Illinois Public Act 99-0906 - Zero Emission Credits (ZECs)*

Illinois Governor Bruce Rauner signed P.A. 99-0906 into law on December 7, 2016.<sup>148</sup> This legislation “enacted a zero emission standard requiring the Illinois Power Agency to procure contracts for electric utilities which serve at least 100,000 customers (*i.e.*, Commonwealth Edison Company (ComEd) and Ameren Illinois) for purchases of ZECs from nuclear fueled generating plants interconnected with PJM or the Midcontinent Independent System Operator, Inc. (MISO) that are reasonably capable of generating ZECs for each delivery year (*i.e.*, June 1 – May 31) in an amount approximately equal to 16% of the amount of MWhs of electricity delivered by the electric utility in calendar year 2014.”<sup>149</sup>

“P.A. 99-0906 requires that the duration of the ZEC contracts be from June 1, 2017 through May 31, 2027, and that the contracts provide that the quantity of ZECs procured from a nuclear generating facility shall be all of the ZECs generated by the facility in each delivery year.”<sup>150</sup> P.A. 99-0906 also “provides that the price for each ZEC shall initially be \$16.50 per MWh, which, according to the state law, is based on the U.S. Interagency Working Group on Social Cost of Carbon’s price in the August 2016 Technical Update using a 3% discount rate, adjusted for inflation due to the ten-year contract duration.”<sup>151</sup>

Beginning “the delivery year commencing June 1, 2023, the ZEC price also increases by \$1 per MWh and continues to increase an additional \$1 per MWh annually” thereafter.<sup>152</sup> “P.A. 99-0906 further provides that the price of ZECs for each delivery year shall be reduced by the amount by which the projected wholesale market price index for the delivery year exceeds a baseline wholesale market

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144. 2018 Haw. Sess. Laws, Act 5, § 1.

145. Order No. 35411, *supra* note 143, at 5.

146. *Id.* at 5-6.

147. *Id.* at 6.

148. S.B 2814, 99th Gen. Assemb., Pub. Act 99-0906 (Ill. 2016).

149. Village of Old Mill Creek v. Star, Complaint, Docket Number 1: 17-CV-01163, p. 48 (N.D. Ill. 2017), <https://statepowerproject.files.wordpress.com/2017/02/il-zec-complaint2.pdf> [hereinafter *Old Mill Creek Complaint*]; Illinois Power Agency Act, 20 Ill. Comp. Stat. 3855/1-75(d-5)(1) (2007).

150. *Id.* at p. 49.

151. *Id.* at p. 50.

152. *Id.*

price index, which P.A. 99-0906 sets at \$31.40 per MWh.”<sup>153</sup> “The wholesale market price index for the applicable delivery year is the sum of projected wholesale energy prices and projected wholesale capacity prices for the delivery year.”<sup>154</sup>

“Under P.A. 99-0906, the electric utilities ComEd and Ameren Illinois will each charge all of their retail customers through their delivery service charges, including those customers who purchase electricity supply from competitive suppliers rather than the electric utility, for the cost of the ZECs sold to the electric utility under its contract with the provider of the ZECs.”<sup>155</sup> “Furthermore, the state law authorizes the utility to recover these costs from all of its retail customers through an ‘automatic adjustment clause tariff.’”<sup>156</sup>

“P.A. 99-0906 is specifically designed so that Exelon Generation’s Quad Cities and Clinton nuclear plants will sell all of the ZECs to ComEd and Ameren Illinois.”<sup>157</sup> “The Quad Cities and Clinton nuclear plants were owned by electric utilities prior to the Illinois Customer Choice and Rate Relief Law of 1997.”<sup>158</sup> “This law allowed the utilities to divest the plants to non-utilities.”<sup>159</sup> “After the nuclear plants were divested to non-utilities and entered the wholesale markets, prices charged by the plants were subject to FERC rather than State of Illinois jurisdiction.”<sup>160</sup> “The Illinois Customer Choice and Rate Relief Law of 1997 also allowed competitive suppliers to sell electricity to Illinois retail customers and required the utilities to deliver the competitive electricity to these customers on a non-discriminatory basis.”<sup>161</sup> This Illinois law specifically found that: ‘All consumers must benefit in an equitable and timely fashion from the lower costs for electricity that result from retail and wholesale competition.’<sup>162</sup>

“The ZEC purchase requirement of P.A. 99-0906 establishes a new state-created electricity price “add” that will inure only to Exelon Generation’s Illinois-based Quad Cities and Clinton nuclear plants.”<sup>163</sup> “The amount of the adder is tied directly to electricity prices in the FERC-regulated PJM and MISO wholesale markets.”<sup>164</sup> “That is, the price of the ZEC will be reduced by the amount the projected wholesale market electricity price index for the applicable delivery year exceeds the baseline wholesale electricity market price index of \$31.40 per MWh.”<sup>165</sup> “In other words, if wholesale electricity prices increase, the ZEC subsidies directly

153. *Old Mill Creek Complaint*, *supra* note 149, at p. 51.

154. *Id.*; 220 ILCS 3855/1-75(d-5)(1)(B)(i).

155. *Old Mill Creek Complaint*, *supra* note 149, at p. 52; 220 ILCS 3855/1-75(d-5)(2); 20 Ill. Comp. Stat. 5/16-108(k) (2017).

156. *Old Mill Creek Complaint*, *supra* note 149, at p. 52; 20 Ill. Comp. Stat. 5/16-108(k) (2017).

157. *Old Mill Creek Complaint*, *supra* note 149, at p. 53.

158. *Id.* at p. 55; 220 Ill. Comp. Stat. 5/16-101 *et seq.*

159. *Old Mill Creek Complaint*, *supra* note 149, at p. 55.

160. *Id.*

161. *Id.*

162. *Id.* (quoting 220 ILCS 5/16-101A(e)).

163. *Old Mill Creek Complaint*, *supra* note 149, at p. 56.

164. *Id.* at p. 57.

165. *Id.*

decrease.”<sup>166</sup> “For example, if the projected electricity market price index for delivery year two is \$38.40 per MWh, the ZEC price for that year will be \$9.50 per MWh.<sup>167</sup> But if the projected electricity market price index for delivery year three is \$39.40 per MWh, the ZEC price for that year will be \$8.50 per MWh.”<sup>168</sup>

## VIII. LOUISIANA

### A. *Rulemaking to Establish Rules Regarding Electric Utility Tariff Filings*

In 2018, the Louisiana Public Service Commission (LPSC) initiated Rulemaking Docket No. R-34738 to establish rules regarding utility tariff filings, site-specific rate filings, and the related reviews thereof.<sup>169</sup> The LPSC opened the docket for the stated purpose of establishing formal procedures to “ensure that electrical utilities [are] apply[ing] non-discriminatory practices” across all classes of customers.<sup>170</sup> Through this proceeding, the LPSC intends to work with electric utilities and other interested parties to establish rules requiring “formal definitions of common electric utility terms,” establishing required record-keeping procedures, and prescribing the process for filing tariffs, rate schedules, and rate riders.<sup>171</sup>

### B. *Tax Impacts of the TCJA; LPSC Docket R-34754*

Pursuant to the TCJA, which became effective January 1, 2018, the maximum federal corporate income tax rate was reduced from 35% to 21%.<sup>172</sup> This impacted LPSC regulated utilities in several ways. First, all utility rates regulated by the LPSC were calculated using the higher tax rate, and, consequently, the “utilities have been collecting taxes in their rates at the 35% level.”<sup>173</sup> However, pursuant to the TCJA, the “utilities will only owe” taxes at the 21% rate, which effectively reduces the utilities’ cost of service.<sup>174</sup> Second, utilities “collected taxes in the past at the higher tax rate” and deferred paying such taxes to the government, portions of which will now be paid under the new, lower rate put into effect by the TCJA.<sup>175</sup> Because these deferred taxes will now be paid at the lower 21% rate, the amounts previously collected from customers now exceed the utilities’ current tax obligations, which means that the TCJA created excess deferred taxes that remain on the utilities books.<sup>176</sup> Absent LPSC action, tax-paying utilities will continue to have excess deferred taxes on their books and will continue collecting and holding

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166. *Id.*

167. *Id.*

168. *Old Mill Creek Complaint*, *supra* note 149, at p. 57.

169. *Notice of Proceeding*, Docket No. R-34738 (La. Pub. Serv. Comm’n, Jan. 25, 2018).

170. *Request for Comments and Notice of Technical Conference, Attachment A: Proposed Rules Regarding Electric Utility Tariff Filings and Related Review*, Docket No. R-34738 (La. Pub. Serv. Comm’n, July 13, 2018).

171. *Id.*

172. *Staff Initial Report and Recommended General Order*, Docket No. R-34754, at 1 (La. Pub. Serv. Comm’n, July 5, 2018) [hereinafter July 5, 2018 Report].

173. *Id.*

174. *Id.*

175. *Id.*

176. *Id.*

the excess revenues, even though the amounts collected are “no longer needed to satisfy” the utilities’ current and future tax obligations due to the new, lower tax rate.<sup>177</sup>

LPSC Special Order No. 13-2018 required the utilities to record the savings caused by the tax reduction as a regulatory liability (deferred liability) until the LPSC adjusted the utilities’ rates to incorporate the new, lower rate.<sup>178</sup> In a subsequent issuance, LPSC General Order in Docket No. R-34754 (issued May 30, 2018), the LPSC addressed Contributions in Aid of Construction and System Development Charges, which were previously exempt but are now taxable under the TCJA.<sup>179</sup> This Order required such amounts already collected to be refunded and recorded as a regulatory asset.<sup>180</sup>

## IX. MISSOURI

### A. *Rulemaking for Small Water and Sewer Utility Rate Case Process*

On February 7, 2018, the Missouri Public Service Commission (MoPSC) issued a rulemaking order intended to streamline the rules that outline the assistance provided by MoPSC Staff to utilities in small water and sewer rate cases.<sup>181</sup> The previous rule (4 CSR 240-3.050), which governed the small water and sewer rate case procedure, was rescinded and replaced with new staff-assisted rate case procedures in rule 4 CSR 240-10.075.<sup>182</sup> This rulemaking resulted in changes to expedite the small rate case process and minimize rate case expense.<sup>183</sup>

### B. *Reduction to Federal Corporate Income Tax Rate*

On January 3, 2018, the MoPSC opened cases for seven IOUs to determine the impact of the TCJA on customer rates.<sup>184</sup> The Commission opened cases “for Union Electric Company d/b/a Ameren Missouri electric and natural gas (Case Nos. ER-2018-0226 and GR-2018-0227); The Empire District Electric Company (Case No. ER-2018-0228); The Empire District Gas Company (Case No. GR-2018-0229), Kansas City Power and Light Company (KCP&L) Greater Missouri Operations Company steam (Case No. HR-2018-0231), Veolia Energy Kansas City, Inc. steam (HR-2018-0232) and Summit Natural Gas of Missouri, Inc. (Case No. GR-2018-0230).”<sup>185</sup>

The MoPSC “directed Ameren Missouri, The Empire District Electric Company, KCP&L Greater Missouri Operations Company, Veolia Energy Kansas

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177. July 5, 2018 Report, *supra* note 172, at 1.

178. *Id.* at 2-3.

179. *Id.* at 3.

180. *Id.* at 3-4.

181. Order of Rulemaking, *Small Utility Rate Case Procedure*, Case No. AX-2018-0050 (Feb. 7, 2018).

182. *Id.*; Mo. Code Regs. Ann. tit. 4 § 240-10.075 (2018).

183. Mo. Code Regs. Ann. tit. 4 § 240-10.075.

184. *Order Opening a Workshop Proceeding Regarding the Effects Upon Missouri Utilities of the Tax Cuts of 2017 and Directing Response*, File No. AW-2018-0174 (Mo. Pub. Serv. Comm’n, Jan. 3, 2018).

185. Press Release, *PSC Establishes Cases to Determine Impact of Federal Tax Cuts on Customer Rates*, MISSOURI PUB. SERV. COMM’N (Feb. 22, 2018), [https://psc.mo.gov/General/PSC\\_Establishes\\_Cases\\_to\\_Determine\\_Impact\\_of\\_Federal\\_Tax\\_Cuts\\_on\\_Customer\\_Rates](https://psc.mo.gov/General/PSC_Establishes_Cases_to_Determine_Impact_of_Federal_Tax_Cuts_on_Customer_Rates).

City, Inc., The Empire District Gas Company and Summit Natural Gas of Missouri, Inc. to show cause, if any, why the MoPSC should not order the companies to promptly file tariffs reducing their rates for every class and category of natural gas, steam, or electric service to reflect the percentage reduction in their federal-state effective income tax rate.”<sup>186</sup> “As part of their response, the companies were directed to state their position on whether the MoPSC could order a reduction in utility rates without considering all relevant factors in an extended general rate case.”<sup>187</sup> In addition, MoPSC directed these companies to “quantify and track all impacts of the TCJA potentially affecting natural gas, steam, or electric service rates from January 1, 2018, going forward.”<sup>188</sup> In addition, the companies must “quantify and track their excess protected and unprotected Accumulated Deferred Income Tax (ADIT) for future possible flow back to ratepayers, and advise the MoPSC on how such flow back may be accomplished.”<sup>189</sup>

## X. NEVADA

### A. *Energy Choice Initiative*

The Nevada Energy Choice Initiative (ECI) seeks to amend the Nevada State Constitution to include the requirement that “electricity markets be open and competitive so that all electricity customers are afforded meaningful choices among different providers, and that economic and regulatory burdens be minimized in order to promote competition and choices in the electric energy market.”<sup>190</sup> In 2016, 72% of Nevada voters approved the ECI, so it will appear again before voters in 2018.<sup>191</sup>

In September 2017, The Governor’s Committee on Energy Choice “requested that the Public Utilities Commission of Nevada (PUCN) initiate [an] investigation to study” (1) the timeline for the implementation of the ECI; (2) changes to Nevada laws “that may be necessary to establish an open and competitive electricity market in Nevada;” and (3) options for establishing competitive retail and wholesale markets.<sup>192</sup> The PUCN also decided to investigate the potential short-and long-term “financial benefits and risks to the residents and businesses of Nevada that may be associated with implementing the Initiative and the best strategies for maximizing any benefits and mitigating any risks.”<sup>193</sup> The PUCN concluded that “commercial and industrial customers,” will likely fare better “than the average Nevada residential family,” and that residential monthly bills are likely to “increase in the short term.”<sup>194</sup>

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186. *Id.*

187. *Id.*

188. *Id.*

189. *Id.*

190. INITIATIVE PETITION – CONST. AM., THE ENERGY CHOICE INITIATIVE, § 1.1 (Feb. 3, 2016).

191. *See generally* Nev. Const. art. 19, § 2 (1)-(3).

192. *Notice of Energy Choice Initiative Investigation and Workshop*, Docket No. 17-10001, 1 (Nev. Pub. Utils. Comm’n, Oct. 11, 2017).

193. *Id.*

194. *Order Accepting Report on the Energy Choice Initiative*, Docket No. 17-10001, at 6 (Nev. Pub. Utils. Comm’n, Apr. 30, 2018).

### B. Implementation of New NEM Program

On June 15, 2017, the Governor of Nevada signed into law Nevada Assembly Bill 405 (AB 405), which made significant changes to Nevada's ("Net Energy Metering") NEM program.<sup>195</sup> It prohibited creating a separate rate class for NEM customers and created a new NEM program.<sup>196</sup> The new NEM program tied the "compensation that customer-generators receive for excess energy put onto the utilities' distribution system to the price of electricity charged by the utilities" and stepped down this credit "based on the total installed capacity of NEM generation under the program."<sup>197</sup> AB 405 also requires a new time-variant offering "designed to expand and accelerate the development and use of energy storage systems."<sup>198</sup>

Pursuant to AB 405, the PUCN conducted a three-day hearing and issued its order on September 1, 2017.<sup>199</sup> In addition to eliminating the separate rate class for NEM customers, Nevada returned to monthly netting of electricity delivered by a utility and electricity fed back to the grid by a customer-generator.<sup>200</sup> The customer is guaranteed anywhere from 95% to 75% of the retail value for the net excess electricity based on where the customer falls in the 80 MW tiers established for customer compensation.<sup>201</sup> A regulatory asset was also established to ensure NV Energy would not sustain a fiscal loss due to AB 405.<sup>202</sup>

### C. Treatment of the TCJA

On January 2, 2018, Nevada Power Company and Sierra Pacific Power Company, both d/b/a NV Energy, filed new tariffs adjusting the Tax Gross-up Rate for line extensions to accommodate the new tax rate of 21% that became effective January 1, 2018 under the TCJA.<sup>203</sup>

On February 14, 2018, both utilities filed plans for returning to customers, through a rate rider, the amounts over-collected from April 1, 2018 through December 31, 2018.<sup>204</sup> These filings were for the respective electric and gas business

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195. *Joint Application of Nevada power Company d/b/a NV Energy Sierra Pacific Power Company d/b/a NV Energy for approval of tariff schedules and rates implementing Assembly Bill 405*, Docket No. 17-07026 (Nev. Pub. Utils. Comm'n, July 28, 2017).

196. *Id.*

197. *Id.*

198. *Id.* at 2.

199. *See generally Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of Tariff Schedules and Rates Pursuant to Assembly Bill 405*, Order Granting I Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405, 2017 WL 3970732 (Nev. P.U.C.).

200. *Id.* at 1.

201. *Id.*

202. *Id.*

203. LoreLei Reid, *Advice Letter No. 484*, Docket No. 18-01-12 (Jan 2, 2018), [http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS\\_2015\\_THRU\\_PRESENT/2018-1/26532.pdf](http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-1/26532.pdf); LoreLei Reid, *Advice Letter No. 604-E*, Docket No. 18-01-13 (Jan. 2, 2018), [http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS\\_2015\\_THRU\\_PRESENT/2018-1/26533.pdf](http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-1/26533.pdf).

204. Elizabeth Elliott, *Advice Letter No. 485*, Docket No. 18-02010 (Feb. 14, 2018), [http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS\\_2015\\_THRU\\_PRESENT/2018-2/27522.pdf](http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-2/27522.pdf); Elizabeth Elliott, *Advice Letter No. 605-E*, Docket No. 18-02010 (Feb. 14, 2018), <http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS>

of NV Energy. The PUCN approved the initial filings and the rate riders went into effect April 1, 2018.<sup>205</sup> The issues related to the over-collections for January 1, 2018 through March 31, 2018 as well as the excess accumulated deferred income tax were set for further proceedings.<sup>206</sup> The PUCN held a hearing on July 10-11, but it had not issued a decision as of August 2018.

On February 20, 2018, the PUCN opened another investigative docket, Docket No. 18-02018, to determine how the other regulated utilities in Nevada should handle the changes created by the TCJA.<sup>207</sup>

## XI. NEW JERSEY

### A. *Modification of Clean Energy and Energy Efficiency Programs and Standards*

On May 23, 2018, New Jersey Governor Phil Murphy signed legislation that increased New Jersey's renewable energy portfolio standard (RPS) to 50% by 2030, modified some of the terms of the state's solar RPS provisions, established an energy storage goal of 600 MW by 2021 and 2,000 MW by 2030, and established increased energy efficiency measures.<sup>208</sup> The legislation also prohibits the costs to customers of the Class 1 renewable energy requirement from exceeding 9% of the total paid for electricity by all customers in the state in 2019, 2020, and 2021, and 7% thereafter.<sup>209</sup> The legislation also established the Community Solar Energy Pilot Program to permit customers of an electric public utility to participate in solar energy projects with a capacity of 5 MW or less that are remote from their properties but within the utility's service territory.<sup>210</sup> The program allows, "for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project."<sup>211</sup> The legislation required the New Jersey Board of Public Utilities (NJBPU) to conduct an energy storage analysis, make changes to the solar renewable energy certificate program, adopt energy efficiency and peak demand reduction programs, adopt the Community Solar Energy Pilot Program, and provide tax credits for certain off-shore wind energy projects.<sup>212</sup> The legislation further required the New Jersey

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[\\_2015\\_THRU\\_PRESENT/2018-2/27523.pdf](#); Elizabeth Elliott, *Advice Letter No 326-G*, Docket No. 18-02012, (Feb. 14, 2018), [http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS\\_2015\\_THRU\\_PRESENT/2018-2/27524.pdf](http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-2/27524.pdf).

205. Order Granting NV Energy Rate Reduction for Nevada Customers Pursuant to Tax Cuts and Jobs Act, Docket Nos. 18-02010, 18-02011, 18-02012 (Nev. Pub. Utils. Comm'n, Mar. 22, 2018).

206. *Id.*

207. *Notice of Investigation, Notice of Request for Comments and Notice of Workshop* (Nev. Pub. Utils. Comm'n, Feb. 23, 2018), [http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS\\_2015\\_THRU\\_PRESENT/2018-2/27693.pdf](http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-2/27693.pdf).

208. Assemb. B. 3723 (N.J. May 23, 2018), codified at NJ Stat. 48-3-87(d)(2)(2018), [http://www.njleg.state.nj.us/2018/Bills/AL18/17\\_.PDF](http://www.njleg.state.nj.us/2018/Bills/AL18/17_.PDF) [hereinafter Bill-3723].

209. *Id.*

210. *Id.* at 24-25.

211. *Id.* at 35.

212. *Id.* at 31.

Department of Labor and Workforce Development to establish programs for training participants to manufacture and service offshore wind energy equipment.<sup>213</sup>

In May 2018, Governor Murphy issued an Executive Order setting forth the priorities for the next Energy Master Plan due in 2019.<sup>214</sup> The Governor directed the 2019 Energy Master Plan to include recommendations for achieving the goal of 2,000 MW of energy storage by January 1, 2030.<sup>215</sup> The Executive Order further directed the NJBPU to, by June 1, 2019, provide a “comprehensive blueprint for the total conversion of the State’s energy production profile to 100% clean energy sources on or before January 1, 2050.”<sup>216</sup>

### *B. Promoting Offshore Wind Energy*

In January 2018, Governor Murphy issued an Executive Order regarding the state’s offshore wind energy production as envisioned in the state’s 2010 Offshore Wind Economic Development Act (OWEDA).<sup>217</sup> The Executive Order set a target of 3,500 MW of offshore wind energy by 2030, and made the NJBPU and the state’s Department of Environmental Protection (NJDEP) responsible for soliciting stakeholder input and developing an Offshore Wind Strategic Plan.<sup>218</sup> The Executive Order also directed the NJBPU to implement the Offshore Renewable Energy Certificate (OREC) program through the approval of OREC pricing plans and to issue a solicitation for proposed offshore wind projects for the generation of 1,100 MW of electric power.<sup>219</sup> The Executive Order called for the NJBPU to initiate discussions with nearby states in the Northeast and Mid-Atlantic region to explore the benefits of regional collaboration on offshore wind and other opportunities to combat climate change.<sup>220</sup> In February 2018, the NJBPU issued an order directing staff to implement the directives of Executive Order No. 8.<sup>221</sup>

### *C. Rejoining Regional Greenhouse Gas Initiative (RGGI)*

On January 29, 2018, Governor Murphy issued an Executive Order requiring New Jersey to re-join the Regional Greenhouse Gas Initiative (RGGI), which is a cooperative effort among nine states in the New England and Mid-Atlantic region to reduce greenhouse gas emissions through a market-based carbon dioxide budget-trading program.<sup>222</sup> The Executive Order noted that New Jersey was an original member of the RGGI at the time of its creation in 2005 but unilaterally

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213. Bill-3723, *supra* note 208, at 35.

214. Exec. Order No. 28, at 1 (N.J. May 23, 2018), <http://nj.gov/infobank/eo/056murphy/pdf/EO-28.pdf>.

215. *Id.* at 3.

216. *Id.* at 2.

217. Exec. Order No. 8, at 2 (N.J. Jan. 31, 2018), <https://nj.gov/infobank/eo/056murphy/pdf/EO-8.pdf>.

218. *Id.* at 2.

219. *Id.* at 2-3.

220. *Id.* at 3.

221. *In the Matter of the Implementation of Executive Order No. 8 on Offshore Wind and the Initiation of an OREC Funding Mechanism and Rulemaking Process*, Docket No. Q018020151, 2018 WL 1175028, 1, 2 (N.J. Bd. Reg. Com. 2018); Press Release, *NJ BPU Approves Order to Implement Governor Murphy’s Offshore Wind Executive Order*, NJ BPU (Feb. 28, 2018), <http://www.bpu.state.nj.us/bpu/newsroom/announcements/pdf/20180228Offshore-Wind-pr.pdf>.

222. Executive Order No. 7, 3 (N.J. Jan. 29, 2018), <https://nj.gov/infobank/eo/056murphy/pdf/EO-7.pdf>.



withdrew from the RGGI as of January 1, 2012.<sup>223</sup> The Executive Order noted that studies indicated that the non-participation in RGGI has caused New Jersey to lose an estimated \$279 million in funds that would have been realized from participation in the budget-trading program.<sup>224</sup> The Executive Order directed the NJDEP and NJBPU to begin discussions and negotiations with the RGGI's member states to reenter the RGGI budget-trading program.<sup>225</sup> It also directed the NJDEP to initiate the administrative rulemaking process for the state's participation in the RGGI and to "include specific guidelines for the allocation of funds realized" from the RGGI carbon trading market, with primary consideration for allocation of the RGGI funds to projects serving communities disproportionately impacted by climate change.<sup>226</sup> On May 22, 2018, the NJBPU "voted to initiate an economic analysis to evaluate the costs and benefits" of rejoining the RGGI.<sup>227</sup>

#### D. Implementation of the TCJA

On January 31, 2018, the NJBU released an order issuing directives and commencing proceedings to examine the impacts of the TCJA on "investor owned gas, electric, water and wastewater companies" with revenues in excess of \$4.5 million.<sup>228</sup> The NJBPU stated that the reduction in the maximum corporate tax rate from 35% to 21% resulting from the TCJA would provide savings to New Jersey public utilities and result in an over collection of tax revenue by the public utilities.<sup>229</sup> In addition to the revenue requirement of the public utilities, the NJBPU noted that the change in the tax rate may impact other rate factors such as the accumulated deferred income tax.<sup>230</sup> Thus, the NJBPU advised that it will make any rate changes resulting from the TCJA effective January 1, 2018, consistent with the effective date of the Act.<sup>231</sup> The NJBPU directed utilities to defer, with interest, the effects of the TCJA effective January 1, 2018.<sup>232</sup> The NJBPU directed each public utility to submit by March 2, 2018, a petition with a detailed calculation of the impact of the TCJA on its revenue requirement by comparing the latest NJBPU-approved test year data and supporting data under the old and new tax laws on an inter- and intra-class basis.<sup>233</sup> Such petitions were to include proposed interim rates to be effective April 1, 2018, and required the filing of proposed final

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223. *Id.* at 1-2.

224. *Id.* at 2.

225. *Id.* at 3.

226. *Id.* at 3-4.

227. *Minutes of the Regular Meeting of the Board of Public Utilities*, NJ BPU (July 25, 2018), <https://www.state.nj.us/bpu/pdf/boardminutes/2018/20180725/July%2025,%202018%20Minutes.pdf>; Press Release, *New Jersey Board of Public Utilities to Seek Economic Assessment of Ramifications of State Rejoining RGGI*, NJ BPU (May 22, 2018), <https://www.nj.gov/bpu/newsroom/announcements/pdf/20180522-rggi.pdf>.

228. *In the Matter of the New Jersey Board of Public Utilities' Consideration of the Tax Cuts and Jobs Act of 2017*, Docket No. AX18010001, at 1-2, 5 (N.J. Bd. Pub. Utils. Jan. 31, 2018) [hereinafter N.J. Tax Cuts and Jobs].

229. *Id.* at 1-2.

230. *Id.* at 2.

231. *Id.*

232. *Id.*

233. N.J. Tax Cuts and Jobs, *supra* note 228, at 2.

rates to be effective July 1, 2018 incorporating all other effects of the TCJA.<sup>234</sup> The NJBPU found that the proposed interim rate reduction and deferred accounting approach it established was in the, “best interests of the public and ratepayers and affected utilities and provides for due process,” because it would reduce the amount of taxes unnecessarily collected as well as the amounts that the affected utilities would have to refund and defer.<sup>235</sup> The NJBPU also directed the utilities to identify proposed treatment of changes, if any, and underlying calculations associated with tax rate reduction, expense and interest deductions, contribution and advances in aid for construction, depreciation, excess accumulated deferred taxes, investment credits, alternative minimum tax, and other elements of rates affected by the changes in the TCJA.<sup>236</sup> The utilities were also required to propose in their filings the mechanism by which the deferrals would be returned to ratepayers.<sup>237</sup> After a period of discovery and comments from stakeholders, the NJBPU is to determine the appropriate adjustment of rates commensurate to the TCJA and approve the appropriate mechanism by which deferred funds will be refunded.<sup>238</sup>

#### *E. Nuclear Power Plants*

On May 23, 2018, Governor Murphy signed legislation establishing a Zero Emission Certificate Program for nuclear power plants.<sup>239</sup> In establishing the need for the ZEC Program, the legislation noted that nuclear power plants meet approximately 40% of New Jersey’s electric power needs and are a, “critical component of the State’s clean energy portfolio because nuclear plants do not emit carbon dioxide, other greenhouse gases, or other pollutants.”<sup>240</sup> The legislation also noted that New Jersey is not projected to meet certain federal and state air quality standards and emission level requirements, and that abrupt retirement of nuclear power plants impedes the state’s ability to meet those requirements.<sup>241</sup> The legislation required the NJBPU, within six months of the enactment of the statute, to complete a proceeding to allow for the commencement of a ZEC Program by establishing a method and application process for determining eligibility and selection of the nuclear power plants and establishing a mechanism for each public utility to purchase ZECs from selected nuclear power plants.<sup>242</sup>

To participate in the ZEC Program, a nuclear plant must provide the NJBPU with: (1) financial information demonstrating its cost projections for the next three years; (2) an explanation of the nuclear plant’s contribution to New Jersey’s air quality and fuel diversity; (3) a statement certifying that the plant will cease operations within three years unless it experiences a material financial change; and (4) an annual certification that the plant is not already receiving any direct or indirect

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234. *Id.* at 5.

235. *Id.* at 4.

236. *Id.* at 3.

237. *Id.*

238. N.J. Tax Cuts and Jobs, *supra* note 228, at 4.

239. S. B. 2313 (N.J. May 23, 2018), [http://www.njleg.state.nj.us/2018/Bills/AL18/16\\_.PDF](http://www.njleg.state.nj.us/2018/Bills/AL18/16_.PDF).

240. *Id.* at 1.

241. *Id.* at 2-3.

242. *Id.* at 5.

state or federal payment or credit.<sup>243</sup> If a selected nuclear plant is already receiving a payment or credit for its environmental attributes, the NJBU must reduce the number of ZECs on a prospective basis to prevent double-payment.<sup>244</sup> The applicant must also pay a fee to the NJBPU in an amount determined by the NJBPU, not to exceed \$250,000.<sup>245</sup>

The NJBPU is to rank eligible nuclear power plants under the criteria established in the legislation for the purpose of determining how ZECs will be distributed.<sup>246</sup> A ZEC under this legislation, is a certificate issued by the NJBPU “representing the fuel diversity, air quality, and other environmental attributes of one megawatt-hour (MWh) of electricity generated by an eligible nuclear power plant” selected by the NJBPU to participate in the ZEC Program.<sup>247</sup> The selected nuclear power plants shall receive ZECs in an amount equal to the number of MWh of electricity it produced in that energy year starting on the date of that plant’s selection.<sup>248</sup> In each year thereafter, each plant shall receive ZECs in an amount equal to the number of MWh of electricity it produced in that energy year for a three-energy year eligibility period.<sup>249</sup> The selected nuclear power plants are also to certify annually that the plant will continue operations save for shutdowns necessary for maintenance and refueling.<sup>250</sup> This legislation requires the NJBPU to determine the price of a ZEC each energy year as described in the legislation and each public utility in the state is required to begin to purchase ZECs on a monthly basis from each selected nuclear power plant as per the requirements in the legislation.<sup>251</sup> To ensure that the ZEC Program remains affordable to retail customers in the State, the NJBPU may, in its discretion, reduce the per kilowatt-hour (kWh) charge so long as the reduced charge is sufficient to achieve the state’s air quality and other environmental attributes by preventing the retirement of eligible nuclear power plants.<sup>252</sup> The legislation describes circumstances when a selected nuclear power plant may be excused from performance and a payment from an electric public utility to the selected nuclear power plant is not due.<sup>253</sup> The legislation also provides protection from layoffs for employees of nuclear plants participating in the ZEC program (except for underperformance or misconduct).<sup>254</sup> No later than 10 years after enactment, the NJBPU shall conduct a study to evaluate the efficacy of the ZEC Program and submit a written report to the Governor, and the NJBPU shall consider the program’s effect on premature retirement of nuclear plants to the state’s air quality, environmental and clean energy goals.<sup>255</sup>

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243. *Id.* at 4-5.

244. S.B. No. 2313, *supra* note 239, at 8-9.

245. *Id.* at 7.

246. *Id.*

247. *Id.* at 4.

248. *Id.*

249. S.B. No. 2313, *supra* note 239, at 7-8.

250. *Id.* at 8.

251. *Id.*

252. *Id.* at 9-10.

253. *Id.* at 10-11.

254. S.B. No. 2313, *supra* note 239, at 11.

255. *Id.* at 11-12.

## XII. NEW YORK

A. *Energy Storage Targets and Roadmap*

In January 2018, New York Governor Andrew M. Cuomo announced an initiative to install 1,500 megawatts (MW) of additional energy storage in New York State by 2025.<sup>256</sup> This initiative builds on the 2017 Energy Storage Deployment legislation, which required the New York Public Service Commission (NYPSC), to establish the Energy Storage Deployment Program to encourage the installation of “qualified energy storage systems,” and requiring the NYPSC to establish a target for the installation of qualified energy storage systems to be achieved through 2030.<sup>257</sup> In the 2018 State of the State address, Governor Cuomo directed New York State energy agencies and authorities to work together during 2018 to generate storage projects through utility procurements.<sup>258</sup> He also announced the commitment of at least \$200 million from the New York Green Bank for storage-related investments and directed the New York State Energy Research and Development Authority (NYSERDA), “to invest at least \$60 million through storage pilots and activities to reduce barriers to deploying energy storage (e.g., permitting, customer acquisition, interconnection, financing costs).”<sup>259</sup>

In response to these directives, on June 21, 2018, the NYDPS and NYSERDA released the New York State Energy Storage Roadmap.<sup>260</sup> The Roadmap identified the near-to-medium term (i.e., 2019-2025) policies needed to achieve the 1,500 MW energy storage target.<sup>261</sup> The actions recommended in the Roadmap fall into seven general categories, five of which are: (1) actions to “send more accurate price signals” on value of peak load reductions; (2) actions to align utility incentives in order to develop a market-based storage sector; (3) procurement initiatives; (4) “clean peak,” actions to, “differentially value peak carbon reductions,”; and (5) wholesale market actions.<sup>262</sup> The actions recommended in the Roadmap were designed with the goal of supporting New York State’s desired end-state vision for energy storage.<sup>263</sup>

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256. Andrew M. Cuomo, EXCELSIOR EVER UPWARD: BUILDING ON A RECORD OF ACCOMPLISHMENT 1, 215 (2018), <http://www.governor.ny.gov/2018StateoftheStateBook> [hereinafter EXCELSIOR].

257. Assemb. Bill 6571, Reg. Sess., 2 (N.Y. Nov. 29, 2017) (codified at NY Pub Service Law § 74) (amending the New York Public Service Law and the Public Authorities Law in relation to establishing the energy storage deployment program), <https://legislation.nysenate.gov/pdf/bills/2017/A6571>; EXCELSIOR, *supra* note 256, at 215-16.

258. EXCELSIOR, *supra* note 256, at 216.

259. *Id.*

260. NEW YORK STATE ENERGY STORAGE ROADMAP (2018), <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2A1BFBC9-85B4-4DAE-BCAE-164B21B0DC3D}> [hereinafter NY ROADMAP].

261. *Id.* at 4.

262. *Id.* at 12.

263. *Id.* at 11.

The Roadmap explained that energy storage technologies will play an increasingly important role in meeting the objectives of Governor Cuomo's Reforming the Energy Vision (REV).<sup>264</sup> In April 2014, the NYPSC issued an order commencing the REV regulatory proceedings, which aimed to align electric utility practices and the NYPSC's paradigm with technological advances in information management and power generation and distribution in order to, "improve system efficiency, empower customer choice, and encourage greater penetration of clean generation" and energy efficiency technologies and practices.<sup>265</sup> Various REV and REV-related proceedings have occurred in the past four years, and energy storage is one of them.<sup>266</sup>

The Roadmap provided a timeline of anticipated storage-related milestones, including: (1) technical conferences to be held by NYPSC and NYSEDA in the third quarter of 2018 to obtain stakeholder feedback; (2) a NYPSC order to be issued in the fourth quarter of 2018 establishing the storage target and deployment mechanisms; and (3) implementation of the directives, beginning in 2019.<sup>267</sup>

### B. Promoting Electric Vehicles

On April 24, 2018, the NYPSC issued an order instituting a proceeding to consider the role of electric utilities in providing infrastructure and rate designs to accommodate electric vehicles (EV) and electric vehicle supply equipment (EVSE).<sup>268</sup> The NYPSC stated that "New York's transportation sector is responsible" for more of New York's carbon dioxide emissions than any other sector, and that electrification of the transportation sector is necessary to meet "New York's State Energy Plan (SEP) targets of reducing greenhouse gas emission 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050."<sup>269</sup> The NYPSC recognized that there are other proceedings considering EV penetration, including the Distributed System Implementation Plan (DSIP), and the filings required by 2017 legislation requiring each electric utility to file an EV Charging Tariff by April 1, 2018.<sup>270</sup> However, the NYPSC concluded that New York's emerging EV market requires regulatory attention to remove inappropriate obstacles and ensure critical electric vehicle supply equipment and infrastructure is in place.<sup>271</sup> The NYPSC directed the establishment of a technical conference to consider various EV-related issues, including how to treat EVs and EVSE as DERs; whether to

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264. NEW YORK STATE, REFORMING THE ENERGY VISION, <https://rev.ny.gov/> (last visited Oct. 4, 2018).

265. *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Case 14-M-0101, 5 (NY Pub. Serv. Comm'n, Apr. 25, 2014) [hereinafter Document No. 1508].

266. NEW YORK STATE, ABOUT THE INITIATIVE, <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument> (last visited Oct. 4, 2018).

267. NY ROADMAP, *supra* note 260, at 15-16 (Figure ES4).

268. *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, Case 18-E-0138 (NY Pub. Serv. Comm'n, Apr. 24, 2018) [hereinafter *EV Supply & Infrastructure Order*].

269. *Id.* at 1.

270. *Id.* at 2, n.5 (citing New York Assembly Bill A.00288) (amending the New York Public Service Law in relation to establishing the electric vehicle charging tariff) (Oct. 23, 2017), (codified at Pub. Serv. Law § 66-0).

271. *Id.* at 3-4, n.7.

adjust tariffs and demand charges; potential utility roles in encouraging EV adoption; compatibility with ongoing regional initiatives and customer, and community needs.<sup>272</sup> The NYPSC also directed the NYDPS to identify issues to be addressed, and to establish the scope of a whitepaper that would be issued thereafter.<sup>273</sup> On May 25, 2018, the NYPSC provided notice that the technical conference will take place on July 18-19, 2018.<sup>274</sup>

### C. Clean Energy Standard Implementation

On November 17, 2017, the NYPSC approved the Clean Energy Standard (CES) Phase 2 Implementation Plan Proposal submitted by NYSERDA and the NYDPS.<sup>275</sup> The NYPSC had originally adopted a Clean Energy Standard and associated framework on August 1, 2016 consistent with the 2015 New York State Energy Plan and the REV.<sup>276</sup> The Clean Energy Standard includes a renewable energy standard (RES) and a Zero-Emissions Credit requirement (ZEC).<sup>277</sup> The RES program requires each New York load-serving entity to procure qualifying Tier 1 renewable energy credits (RECs), produced by renewable resources, in a defined and increasing percentage of its total load.<sup>278</sup> Load-serving entities may meet their RES obligations by either purchasing RECs from NYSERDA or other sellers, or by making compliance payments to NYSERDA.<sup>279</sup> The RES also includes a Tier 2 maintenance program to provide support to those “at risk” eligible facilities (*i.e.*, small hydro, wind facilities and certain biomass direct combustion facilities) that have demonstrated that they are not economically viable without additional support.<sup>280</sup> Under the ZEC program, each load-serving entity is required to purchase from NYSERDA the percentage of ZECs that represents the proportionate share of the electric energy load it serves in relation to the total electric energy load.<sup>281</sup>

In February 2017, the NYPSC approved the CES Phase 1 Implementation Plan, which addresses eligibility of renewable energy resources to qualify for Tier 1 RECs, long-term procurement of RECs, load-serving entity demonstration of compliance and other reporting requirements.<sup>282</sup> In November 2017, the NYPSC

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272. *Id.* at 4-5.

273. *EV Supply & Infrastructure Order*, *supra* note 268, at 5-7.

274. Notice of Technical Conference, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, Case 18-E-0138 (NY Pub. Serv. Comm’n, May 25, 2018).

275. Order Approving Phase 2 Implementation Plan, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Case 15-E-0302 (NY Pub. Serv. Comm’n, Nov. 17, 2017) [hereinafter Phase 2 Implementation Order].

276. Order Adopting a Clean Energy Standard, *Proceeding on Motion of the Commission to Implement a Large Scale Renewable program and a Clean Energy Standard*, Case 15-E-0302, at 2, 12 (NY Pub. Serv. Comm’n, Aug. 1, 2016) [hereinafter Order Adopting Clean Energy Standard].

277. *Id.* at 13-14.

278. *Id.* at 14-17.

279. *Id.* at 16.

280. *Id.* at 17-18, 117.

281. Order Adopting a Clean Energy Standard, *supra* note 276, at 19-20.

282. Order Approving Phase 1 Implementation Plan, *Proceeding on Motion of the Commission to Implement a Large Scale Renewable Program and a Clean Energy Standard*, No. 15-E-0302, at 33 (NY Pub. Serv. Comm’n Case Feb. 22, 2017); *see also* Clean Energy Standard Final Phase 2 Implementation Plan, Case 15-E-

approved the CES Phase 2 Implementation Plan Proposal.<sup>283</sup> The proposal provides recommendations for: (1) modifying the annual RES targets for load-serving entities ; (2) establishing a protocol for annually testing divergence from the targets; (3) policies for the sale of Tier 1 RECs procured by NYSERDA; (4) calculating the alternative compliance payment for 2018; and (5) providing detail for post-2018 REC long-term procurement design.<sup>284</sup> In the Phase 2 Implementation Order, the NYPSC required NYSERDA to post on its website as part of its annual CES Compliance Reporting, the methodology for calculating the statewide fuel mix for New York State.<sup>285</sup> The NYPSC also directed NYSERDA to report on an annual basis, RES program expenses revenues (*e.g.*, net proceeds from the sale of RECs, alternative compliance payments received, interest earnings) and program expenses, and any surplus or shortfall for the year, with a proposal for using any surplus of more than 25%.<sup>286</sup> Other directives included the filing of a Final Phase 2 Implementation Plan, which NYSERDA and NYDPS Staff filed on December 18, 2017.<sup>287</sup>

#### D. Value of Distributed Energy Resources

On February 22, 2018, the NYPSC issued an order to expand eligibility for participation in “Value Stack Tariffs.”<sup>288</sup> Value Stack Tariffs were implemented as part of the NYPSC’s March 9, 2017 order directing the compensation for eligible distributed energy resources (DERs) that transitioned from net energy metering (NEM) to the “Value Stack.”<sup>289</sup> The Value Stack is a methodology that bases compensation of eligible DERs “on the actual, calculable benefits that DERs create.”<sup>290</sup> In addition, “the VDER Phase One Order also created a transitional compensation mechanism” called Phase One NEM.<sup>291</sup> It “offers compensation similar to NEM” for a limited period to “certain eligible projects that were in a late stage of development” at the time of the VDER Phase One Order and to “all eligible on-site mass market projects,” for example rooftop solar, that was interconnected before January 1, 2020.<sup>292</sup>

Pursuant to the Order, “a project is eligible for compensation based on the Value of Distributed Energy Resources (VDER) Tariff,” if, “based on its size and

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0302, at 1, (NY Pub. Serv. Comm’n, Dec. 18, 2017) (filed by NYSERDA and NYDPS Staff) [hereinafter CES Phase 2 Implementation Plan].

283. Phase 2 Implementation Order, *supra* note 275.

284. *Id.* at 2-3.

285. *Id.* at 13, 25.

286. *Id.* at 25.

287. *Id.*; *see generally* CES Phase 2 Implementation Plan, *supra* note 282.

288. Order on Phase One Value of Distributed Energy Resources Project Size Cap and Related Matters, *In the Matter of the Value of Distributed Energy Resources*, Case No. 15-E-0751 (NY Pub. Serv. Comm’n, Feb. 22, 2018) [hereinafter VDER Phase One Project Size Cap Order].

289. *Id.* at 1 (citing Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters, *In the Matter of the Value of Distributed Energy Resources*, Case No. 15-E-0751 (NY Pub. Serv. Comm’n, Mar. 9, 2017) [hereinafter VDER Phase One Order]).

290. VDER Phase One Project Size Cap Order, *supra* note 288, at 1.

291. *Id.* at 1.

292. *Id.* at 1-2.

technology, it would be eligible for NEM pursuant to [New York] Public Service Law Sections 66-j and 66-l” (*i.e.*, “solar, wind, hydroelectric, farm-based anaerobic digesters, and fuel cells” and combined heat and power units).<sup>293</sup> In the VDER Phase One Project Size Cap Order, the NYPSC sought to “unlock the economy of scale and efficiency benefits that will result in the development of additional clean generation without impacting nonparticipating ratepayers.”<sup>294</sup> It did so by expanding “eligibility for participation in Value Stack Tariffs to projects” (except for combined heat and power generators, which required more detailed analysis) from the 2 MW threshold to up to 5 MW.<sup>295</sup> The NYPSC permitted developers to submit applications for new projects sized at between 2 MW and 5 MW as well as to propose expansions of existing projects and projects in the interconnection queue.<sup>296</sup> However, the NYPSC will not permit developers to consolidate projects already in the interconnection queue until the NYPSC has considered and acted on the amendments to the Standard Interconnection Requirements, which the NYDPS Staff proposed on December 20, 2017.<sup>297</sup> The NYPSC also noted that it was not, in the VDER Phase One Project Size Cap Order, increasing the total capacity allocation for community distributed generation, and thus was not increasing the total potential customers for DER suppliers.<sup>298</sup> The NYPSC stated that its VDER Phase One Project Size Cap Order was a “major step in decreasing DER project soft costs” to enable and accelerate the development of DERs “with limited or no impact on nonparticipating ratepayers” in furtherance of the RVV’s objectives.<sup>299</sup>

### XIII. OHIO

#### A. *Financial Support for Ohio Electric Distribution Utilities*

The Public Utilities Commission of Ohio (PUCO) has been asked to analyze several issues relating to two coal plants owned by the Ohio Valley Electric Corporation (OVEC).<sup>300</sup> The OVEC plants were originally constructed by a consortium of utilities to provide power to a single customer, a uranium-enrichment facility operated by the Atomic Energy Commission.<sup>301</sup> Power from the OVEC plants was sold to the uranium enrichment plants under a contract approved by the

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293. *Id.* at 2.

294. *Id.* at 3.

295. VDER Phase One Project Size Cap Order, *supra* note 288, at 3, 13.

296. *Id.* at 16.

297. *Id.* at 17.

298. *Id.* at 11.

299. *Id.* at 18.

300. Concurring Opinion of Chairman Asim Z. Haque, Case Nos. 14-1693-EL-RDR, 14-1694-EL-AAM, (Ohio Pub. Utils. Comm’n, Mar. 31, 2016).

301. H.B. 239, 132nd Gen. Assemb., Fiscal Note & Local Impact Statement, Ohio Legis. Serv. Comm’n, 2 (Oct. 5, 2017), <https://www.legislature.ohio.gov/download?key=7689&format=pdf>. FirstEnergy-Ohio, which collectively includes The Cleveland Electric Illuminating Company (CEI), The Toledo Edison Company (TE), and Ohio Edison Company (OE), Duke Energy-Ohio, Inc. (Duke-Ohio), Ohio Power Company (AEP-Ohio), and The Dayton Power and Light Company (DP&L), were all part of the utility consortium that constructed the OVEC plants. *Id.*



FERC, with the utility co-owners able to utilize any excess power from the coal plants in proportion to their ownership shares.<sup>302</sup> In the early 2000s, the uranium enrichment facility was authorized to source power from the facility from the market instead of from the OVEC plants.<sup>303</sup> Although the original purpose for the OVEC plants had ended, the utility co-owners elected to extend the operation of the OVEC plants, making significant upgrades in the process.<sup>304</sup>

Under the FERC-approved contract between OVEC and the sponsoring utility companies, Duke-Ohio has an obligation to cover 9.00% of OVEC's costs and a corresponding right to purchase up to 9.00% of OVEC's energy output; DP&L's share is 4.90%; and AEP-Ohio's share is 19.93%.<sup>305</sup> FirstEnergy-Ohio had a 4.85% share; however, as discussed below, pursuant to restructuring in the state, FirstEnergy-Ohio transferred its share to an unregulated affiliate of FirstEnergy-Ohio.<sup>306</sup>

That restructuring occurred through legislation passed in 1999 and included a directive that each EDU separate its generation assets from its transmission and distribution assets.<sup>307</sup> Ohio law also allowed electric utilities to functionally separate the generation business for an interim period.<sup>308</sup>

FirstEnergy-Ohio was the first EDU to divest its generation assets, including its ownership interest in OVEC, to an affiliate.<sup>309</sup> Through a series of cases between 2012 and 2016, Duke-Ohio, AEP-Ohio, and DP&L divested their generation assets to affiliates; however, these three utilities also claimed they could not divest their OVEC interests.<sup>310</sup> Over this same timeframe, the PUCO began authorizing standard service offer (SSO) plans that relied on competitive auctions to

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302. *Id.*

303. Concurring Opinion of Chairman Asim Z. Haque, *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case Nos. 13-2385-EL-SSO et al. at 2 (Ohio Pub. Utils. Comm'n, Nov. 3, 2016).

304. Direct Testimony of Tyler Comings on Behalf of Sierra Club, *In the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Stranded Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, Case No. 14-1297-EL-SSO (Ohio Pub. Utils. Comm'n, Dec. 22, 2014).

305. H.B. 239, *supra* note 301, at 3.

306. Transcript Vol. 1, *In the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Stranded Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, at 31, Case No. 14-1297-EL-SSO (Ohio Pub. Utils. Comm'n, 2015).

307. Am. Sub. S.B. No. 3, 148 Ohio Laws, Part IV, 7962.

308. Ohio Rev. Code § 4928.17.

309. Order Authorizing Disposition and Acquisition of Jurisdictional Facilities, *First Energy Corp.*, FERC Docket No. EC05-84-000 (issued Sept. 1, 2005).

310. Opinion and Order, *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service*, Case Nos. 11-3549-EL-SSO et al., (Ohio Pub. Utils. Comm'n, Nov. 22, 2011) [hereinafter *Duke Energy Application Opinion and Order*]; Opinion and Order, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO et al. (Ohio Pub. Utils. Comm'n, Aug. 8, 2012); Opinion and Order, *In the Matter of the Application of The Dayton Power and Light Company for Approval of its Electric Security Plan*, Case Nos. 12-426-EL-SSO et al., (Ohio Pub. Utils. Comm'n, Sept. 4, 2013).

secure retail electric generation service for non-shopping customers served under the SSO.<sup>311</sup>

Duke-Ohio, AEP-Ohio, and DP&L have sought, and in the case of the latter two, obtained approval to use their OVEC generation entitlement as a hedge against market-price volatility.<sup>312</sup> The purported hedge occurs through a process where these utilities purchase power from OVEC under the FERC-approved Power Purchase Agreement (PPA) at a cost-based price and then liquidate that power into the PJM Interconnection, LLC (PJM) capacity and energy markets.<sup>313</sup> The difference is passed back onto the retail customers of the EDUs through an unavoidable charge or credit.<sup>314</sup>

Challenges to this structure have been lodged based on state and federal claims. Under state law, challengers assert the charge allows for the collection of stranded costs; is not a term that the PUCO can authorize under an electric security plan (ESP); does not actually operate as a hedge; and is likely to cost Ohio retail customers hundreds of millions of dollars over the life of the approved charges.<sup>315</sup> Challengers have also asserted that the charges are preempted under federal law, citing the U.S. Supreme Court's recent ruling in *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016).<sup>316</sup> The AEP-Ohio charge/hedge is currently before the Ohio Supreme Court; the DP&L charge/hedge is pending on rehearing before the PUCO; and the Duke-Ohio charge/hedge is pending review by the PUCO.<sup>317</sup>

FirstEnergy-Ohio had also proposed its own "hedge" type mechanism and sought to include all the generation owned by its affiliate, including an interest in

311. See generally Duke Energy Application Opinion and Order, *supra* note 310.

312. Entry, *In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case Nos. 17-1263-EL-SSO et al., (Ohio Pub. Utils. Comm'n, Dec. 20, 2017) (ordered that Duke be authorized to conduct SSO auctions as described in its December 5, 2017 filing, as revised on December 6, 2017); Opinion and Order, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case Nos. 14-1693-EL-RDR et al., (Ohio Pub. Utils. Comm'n, March 31, 2016); Opinion and Order, *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan*, Case Nos. 16-1852-EL-SSO et al., (Ohio Pub. Utils. Comm'n, Apr. 25, 2018); *In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan*, Case Nos. 16-395-EL-SSO et al., Opinion and Order (Ohio Pub. Utils. Comm'n, Oct. 20, 2017).

313. Opinion and Order, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case Nos. 14-1693-EL-RDR et al., at 43 (Ohio Pub. Utils. Comm'n, March 31, 2016).

314. *Id.*

315. Fifth Entry on Rehearing, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case Nos. 14-1693-EL-RDR et al., (Ohio Pub. Utils. Comm'n, April 5, 2017). Ohio law allowed a one-time opportunity to request to recovery of stranded costs through transition revenue as part of the 1999 restructuring legislation. That legislation, and subsequent legislation reflected in Senate Bill 221, (S.B. 221), which modified the SSO-related statutes in 2008, prohibit EDUs from collecting further transition revenue or its equivalent. An ESP is one of two options an Ohio EDU can utilize to fulfill its SSO obligation under Ohio law. *Id.*

316. Opinion and Order, *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case Nos. 14-1693-EL-RDR et al., at 103 (Ohio Pub. Utils. Comm'n, March 31, 2016).

317. See generally Ohio Supreme Court Case No. 17-0749 and associated docket entries.

OVEC.<sup>318</sup> The PUCO initially authorized that hedge; however, after a finding by FERC that the transaction would have to pass FERC's affiliate standards, the PUCO reversed course and denied the entirety of FirstEnergy-Ohio's hedge proposal.<sup>319</sup> As noted above, unlike the other three utilities, FirstEnergy-Ohio's OVEC interest had been divested to its affiliate.<sup>320</sup>

The PUCO, however, ultimately provided FirstEnergy-Ohio with \$132.5 million/year, after-tax, of financial support through a Distribution Modernization Rider (DMR).<sup>321</sup> The DMR would produce a portion of the cash flow the PUCO determined necessary to maintain the credit ratings of the parent of the FirstEnergy-Ohio EDUs and position FirstEnergy-Ohio to be able to make capital investments to modernize its distribution system.<sup>322</sup> The DMR was authorized for three years with the possibility of a two-year extension.<sup>323</sup>

Challengers opposed FirstEnergy-Ohio's DMR claiming it would allow for the collection of stranded costs under the argument that the DMR simply replaced the rejected PPA generation charge/hedge mechanism.<sup>324</sup> Challengers also asserted the charge was not among the terms that could be authorized under an ESP.<sup>325</sup> FirstEnergy-Ohio's DMR charge has been appealed to the Ohio Supreme Court.<sup>326</sup> The appeal has been fully briefed and is awaiting oral arguments.

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318. Opinion and Order, *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, Case Nos. 14-1297-EL-SSO et al., (Ohio Pub. Utils. Comm'n, March 31, 2016).

319. Order Granting Complaint, *Electric Power Supply Assoc. v. FirstEnergy Solutions Corp.*, EL16-34, 155 FERC ¶ 61,101, (Apr. 27, 2016). Like FirstEnergy-Ohio, AEP-Ohio also had a proposal that had initially been approved to include all the generation assets owned by its affiliate, which it had previously divested. AEP-Ohio's proposal was also initially approved by the PUCO but stalled after FERC also required the AEP transaction to pass its affiliate standards. DP&L had also initially proposed the same all-generation approach but unilaterally withdrew it in light of the rulings by FERC with respect to FirstEnergy-Ohio and AEP-Ohio. *Id.*

320. Transcript Vol. 1, *In the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Stranded Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, at 31, Case No. 14-1297-EL-SSO (Ohio Pub. Utils. Comm'n, 2015).

321. Fifth Entry on Rehearing, *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, Case Nos. 14-1297-EL-SSO et al., at p. 202 (Ohio Pub. Utils. Comm'n, Oct. 12, 2016) [hereinafter Fifth Entry on Rehearing].

322. *Id.* at p. 197.

323. *Id.* at p. 210.

324. See generally Fifth Entry on Rehearing, *supra* note 321.

325. *Id.* at p. 187.

326. Appeal from Public Utilities Commission, *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.*, Case No. 2017-1444 (Ohio Pub. Utils. Comm'n, July 31, 2018).

Like FirstEnergy-Ohio, DP&L was authorized to collect a DMR for the same reasons as FirstEnergy-Ohio.<sup>327</sup> DP&L's non-bypassable DMR collects \$105 million/year, before-tax, for three years with a possible two-year extension.<sup>328</sup>

Legislative proposals have also sought to authorize OVEC charges like those that the PUCO has authorized for AEP-Ohio and DP&L.<sup>329</sup> House Bill 239 (H.B. 239) and Senate Bill 155 (S.B. 155) would allow an EDU to recover costs through a non-bypassable charge that they would incur because of their retention of an equity interest in the OVEC related generating units.<sup>330</sup> The bills were written for Ohio EDUs that hold an equity interest in OVEC, *i.e.* the legislation excludes FirstEnergy-Ohio which, as noted above, transferred its interest to an affiliate. H.B. 239 and S.B. 155 would place a cap on the monthly non-bypassable charges for residential and industrial customers.<sup>331</sup> H.B. 239 was introduced in the Ohio House on May 23, 2017 and was referred to the House Public Utilities Committee.<sup>332</sup> S.B. 155 was introduced in the Ohio Senate on May 23, 2017 and was referred to the Senate Public Utilities Committee.<sup>333</sup> As of July 2018, these bills remain pending in these respective committees.

#### B. Financial Support for FirstEnergy -Ohio Nuclear Plants

In an effort to recognize the emission benefits of maintaining nuclear plants House Bill (H.B.) 381 and Senate Bill (S.B.) 128 would establish a zero-emission nuclear resource (ZENR) program requiring each EDU with a ZENR located in its service area to purchase zero-emissions nuclear credits (ZENCs) at an initial price of \$17 per ZENC.<sup>334</sup> The bills would also require retail customers to fund the direct and indirect costs of the ZENCs through non-bypassable charges payable over a period of 16 years.<sup>335</sup> The bills would cap the ZENC charges for commercial, industrial, and residential customers.<sup>336</sup> Both in-state and out-of-state Nuclear Energy Resources (NERs) must comply with certain requirements. For example, an entity headquartered in Ohio that operates a ZENR must keep the headquarters in Ohio during the period it receives ZENC payments and must maintain its employment levels. The PUCO would be required to allocate ZENCs to the EDUs based on total end user consumption. The PUCO would collect the ZENC revenue and any earnings on the revenue would go to the benefit of Ohio's General Revenue Fund. H.B. 381 was introduced in the Ohio House on October 11, 2017 and

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327. Opinion and Order, *In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan*, Case No. 16-395-EL-SSO et al., (Ohio Pub. Utils. Comm'n, Oct 20, 2017).

328. *Id.*

329. H.B. 239, 132nd Gen. Assemb (2017); S.B. 155, 132nd Gen. Assemb (2017).

330. H.B. 239, 132nd Gen. Assemb (2017); S.B. 155, 132nd Gen. Assemb (2017).

331. *See generally* H.B. 239, 132nd Gen. Assemb.; S.B. 155, 132nd Gen. Assemb.

332. *See generally* H.B. 239, 132nd Gen. Assemb.

333. *See generally* S.B. 155, 132nd Gen. Assemb.

334. Samuel Randazzo et. al., *What's up at the Ohio General Assembly*, 22ND ANNUAL OHIO ENERGY CONFERENCE, 5 (Feb. 20, 2018), <https://mecseminars.com/sites/default/files/presentation-files/Tues.%20Key-note%205%20-%20Ohio%20General%20Assembly.pdf>.

335. *Id.*

336. *Id.*

as of July 2018 was pending in the Ohio House Public Utilities Committee.<sup>337</sup> S.B. 128 was introduced in the Ohio Senate on April 4, 2017 and as of July 2018 was pending in the Senate Public Utilities Committee.<sup>338</sup>

### C. *Modification to Ohio Energy Efficiency Mandates*

In 2008, Ohio enacted energy efficiency portfolio mandates.<sup>339</sup> In 2015, Substitute Senate Bill (S.B.) 310 introduced reforms to Ohio's energy portfolio mandates.<sup>340</sup> SB 310 was passed by the Ohio General Assembly on June 4, 2014, and required the disclosure of mandate costs to customers and streamlined the ability of larger mercantile customers to opt out of cost compliance with Ohio's mandates.<sup>341</sup> S.B. 310 also modified the existing portfolio requirements and specified a 22% mandated reduction in electricity demand by 2025 and 12.5% of supply side alternative energy resources.<sup>342</sup>

House Bill 114 (H.B. 114) proposes further modifications to Ohio's portfolio requirements.<sup>343</sup> If passed, the bill would decrease the cumulative energy efficiency mandate from 22.7% to 17.2%; clarify counting for the purposes of implementing for complying with the energy efficiency and peak demand reduction mandates; and clarify the energy efficiency and peak demand reduction mandates terminate by the end of 2027.<sup>344</sup> H.B. 114 would also expand the streamlined opt-out for all mercantile customers.<sup>345</sup> Under H.B. 114, all mercantile customers could elect to avoid the costs and benefits of the energy efficiency and peak demand reduction mandates by January 1, 2019.<sup>346</sup> This would allow mercantile customers to undertake their own efficiency measures.<sup>347</sup>

The Ohio House passed H.B. 114 on March 30, 2017, and the bill was introduced in the Ohio Senate on April 5, 2017.<sup>348</sup> As of July 2018, H.B. 114 was pending in the Ohio Senate Energy and Natural Resources Committee.<sup>349</sup>

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337. *Id.* at 8

338. *Id.* at 7.

339. ENERGY.GOV, ENERGY EFFICIENCY PORTFOLIO STANDARD, <https://www.energy.gov/savings/energy-efficiency-portfolio-standard-0> (last visited Oct. 15, 2018).

340. Sub. S.B. No. 310, 130th Gen. Assemb. (2015).

341. *Id.* at 25.

342. ENERGY.GOV, ENERGY EFFICIENCY PORTFOLIO STANDARD, <https://www.energy.gov/savings/energy-efficiency-portfolio-standard-0>; *see also* OHIO REV. CODE ANN. § 4928.64, 4928.66 (2008).

343. H.B. No. 114, 132nd Gen. Assemb. (2017); Randazzo, *supra* note 334, at 2.

344. Randazzo et al., *supra* note 334, at 1-2.

345. *Id.* at 3.

346. *Id.* Ohio law defines "mercantile customer" as "a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states." OHIO REV. CODE ANN. § 4928.01(A)(19).

347. *Id.*

348. Randazzo, *supra* note 334, at 3.

349. *Id.*

## XIV. OKLAHOMA

A. *OCC Awards PSO Rate Increase*

On June 30, 2017, Public Service Company of Oklahoma (PSO) filed a rate case with the Oklahoma Corporation Commission (OCC) requesting a \$156 million base rate increase.<sup>350</sup> PSO was seeking reimbursement for more than \$625 million in new electrical infrastructure.<sup>351</sup> On January 31, 2018, the OCC approved a rate increase of \$80 million dollars.<sup>352</sup>

B. *OG&E Reaches Settlement with OCC and Oklahoma Attorney General on Utility Rate Case*

On January 16, 2018, Oklahoma Gas and Electric (OG&E) filed a rate case with the OCC requesting a base rate increase.<sup>353</sup> On June 19, 2018, the Oklahoma Corporation Commissioners approved a rate case settlement between OG&E, the Oklahoma Attorney General's office, consumer groups, and the OCC's Public Utility Division.<sup>354</sup> The settlement resulted in over \$82.5 million in savings for ratepayers.<sup>355</sup>

C. *Task Force to Study OCC*

During the 2017 legislative session, the Oklahoma Legislature passed legislation creating an executive-level task force to study the operation of the OCC and suggest possible changes to the structure and function of the OCC.<sup>356</sup> On August 7, 2017, the Governor of Oklahoma issued an executive order establishing the Second Century Corporation Commission Task Force.<sup>357</sup> Micheal Teague, Oklahoma's secretary of energy and environment, will lead the Task Force.<sup>358</sup> The Task Force will issue its report by November 15, 2018.<sup>359</sup>

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350. *Application of Public Service Company of Oklahoma for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma*, PUD Cause No. 201700151 (Okla. Corp. Comm'n, June 30, 2017).

351. *Direct Testimony of Steven L. Fate on Behalf of Public Service Company of Oklahoma*, PUD Cause No. 201700151, at p. 9 (Okla. Corp. Comm'n, June 30, 2017).

352. Final Order, Order No. 672864, PUD Cause No. 201700151 (Okla. Corp. Comm'n, Jan. 31, 2018).

353. *Application of Oklahoma Gas and Electric for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma*, PUD Cause No. 201700496, at p. 3 (Okla. Corp. Comm'n, Jan. 16, 2018).

354. Final Order, Order No. 679358, *In the Matter of the Application of Oklahoma Gas and Electric Company for an order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma*, PUD Cause No. 201700496 (Okla. Corp. Comm'n, June 19, 2018).

355. Jack Money, *State Regulators Approve OG&E Rate Cut*, THE OKLAHOMAN (June 19, 2018), <https://newsok.com/article/5598602/state-regulators-approve-oge-rate-cut>.

356. Oklahoma Legislature, Bill Summary for HB 1377, 1st Session of 56th Legislature (2017), <http://www.oklegislature.gov/BillInfo.aspx?Bill=hb1377>.

357. Exec. Order No. 2017-23, *Formation of the Second Century Corporation Commission Task Force, Oklahoma Governor* (Aug. 7, 2017), <https://www.sos.ok.gov/documents/executive/1569.pdf>.

358. Paul Monies, *Task Force on Oklahoma Corporation Commission Holds First Meeting*, THE OKLAHOMAN (Sept. 7, 2017), <https://newsok.com/article/5563041/task-force-on-oklahoma-corporation-commission-holds-first-meeting>.

359. *Id.*

## XV. PENNSYLVANIA

A. *Final Implementation Order for Act 40*

On April 19, 2018, the Pennsylvania Utility Commission (PA PUC) approved a Final Implementation Order for Act 40.<sup>360</sup> Act 40 modified Pennsylvania's Alternative Energy Portfolio Standards (AEPS) Act, which requires Electric Distribution Companies (EDC) and Electric Generation Suppliers (EGS) to obtain a portion of the electricity they sell from alternative energy resources, including solar photovoltaic (solar PV).<sup>361</sup> In the past, EDCs and EGSs could meet the solar PV requirement by purchasing solar renewable energy credits (SRECs) produced from solar energy generated anywhere in the PJM regional transmission grid.<sup>362</sup> Act 40 effectively "closes the borders" by requiring that the solar AEPS requirement be met by SRECs produced in Pennsylvania.<sup>363</sup>

In its Final Implementation Order, the PA PUC addressed the extent SRECs from out-of-state can be "grandfathered."<sup>364</sup> First, the PA PUC determined that qualifying out-of-state SRECs generated prior to the passage of Act 40 and "banked" in PJM's GATS tracking system would retain their solar attributes and be available to count toward the AEPS solar requirement for three years, consistent with all other banked SRECs.<sup>365</sup>

Second, the PA PUC determined that out-of-state generation facilities may continue to generate SRECs if they meet two conditions: they must (1) possess existing certification as AEPS solar facilities; and (2) have an existing contract for the sale of solar credits to a PA EDC or EGS.<sup>366</sup> If both conditions are satisfied, a solar generation facility may continue to provide contracted SRECs until the contract expires.<sup>367</sup> After the conclusion of existing contracts, the borders will be closed.<sup>368</sup>

The PUC also clarified that out-of-state solar PV systems can still be eligible to meet the Tier I *non*-solar AEPS Act obligations of Pennsylvania EDCs and EGSs.<sup>369</sup>

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360. Final Implementation Order, *Implementation of Act 40 of 2017*, Docket No. M-2017-2631527 (Pa. Pub. Util. Comm'n, Apr. 19, 2018) [hereinafter Act 40 Order].

361. *Id.* at 2.

362. *Id.* at 4-6.

363. *Id.* at 5-6.

364. *Id.* at 16.

365. Act 40 Order, *supra* note 360, at 30.

366. *Id.* at 32, 34. The certification and contract must have been in effect by October 30, 2017. For these SRECs to continue to qualify to meet an EDC or EGS's solar PV requirement, the EDC or EGS was required to petition the Commission within 60 days of the Final Implementation Order.

367. *Id.* at 28.

368. *Id.* at 31.

369. *Id.* at 29.

### B. *Final Combined Heat and Power Policy Statement*

On April 5, 2018, the PA PUC adopted a Final Policy Statement seeking to promote the development of combined heat and power (CHP) systems and facilities in Pennsylvania.<sup>370</sup> The Final Policy Statement seeks to encourage EDCs and natural gas distribution companies (NGDCs) to prioritize CHP in their energy efficiency plans, marketing, as well as outreach efforts.<sup>371</sup>

In the Final Policy Statement, the PA PUC noted several challenges of CHP development.<sup>372</sup> These challenges include (1) perceived difficulty in justifying capital investment, in part due to the long-term payback requirements of CHP; (2) costs of purchasing backup power during planned plant maintenance and unplanned downtime; and (3) lack of national and state standards for the interconnection of distributed generation technologies, as well as the attendant interconnection fees and procedures.<sup>373</sup>

In light of these challenges, the Final Policy Statement requires EDCs and NGDCs to provide biennial reports on their strategies, programs, and other initiatives supporting CHP.<sup>374</sup>

With respect to utility interconnection rules and fees, the PA PUC explained “there should be streamlined interconnection procedures and fees” relating to all types of generation, but stated that they should be addressed in a separate proceeding.<sup>375</sup> The PA PUC also created a CHP working group to discuss CHP reporting, processes, and related topics.<sup>376</sup> The goal of the working group is to encourage the deployment of CHP initiatives in Pennsylvania and to reduce obstacles to CHP development.<sup>377</sup> The CHP working group is currently in progress and comprised of various stakeholders on this issue.<sup>378</sup>

Although the PA PUC did not establish any new financial incentives for CHP development, it did require PA PUC staff to identify government agency programs that provide financial support, as well as other support, for the development of CHP.<sup>379</sup>

Finally, the PA PUC revised the definition of CHP by adding the federal Department of Energy’s descriptions of CHP into 52 Pa. Code § 69.3201.<sup>380</sup>

### C. *Proposed Policy Statement on Alternative Ratemaking & House Bill 1782*

On May 23, 2018, after two years of considering alternative ratemaking methodologies, the PA PUC issued a Proposed Policy Statement Order. In the

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370. Final Policy Statement, *Final Policy Statement on Combined Heat and Power*, Docket No. M-2016-2530484 (Pa. Pub. Util. Comm’n, Apr. 5, 2018) [hereinafter Final Policy Statement].

371. *Id.* at 1-2.

372. *Id.* at 3.

373. *Id.*

374. *Id.* at 4.

375. Final Policy Statement, *supra* note 370, at 9.

376. *Id.* at 11.

377. *Id.*

378. *Id.* at 13.

379. *Id.* at 24.

380. Final Policy Statement, *supra* note 370, at 15.



Order, the PA PUC proposed guidelines for considering whether alternative rate-making methodologies should be implemented.<sup>381</sup>

Following the Proposed Policy Statement Order, on Thursday, June 28, 2018, the Governor signed House Bill 1782 into law, explicitly permitting the PA PUC to approve alternative ratemaking mechanisms for electric, natural gas, water, and wastewater utilities.<sup>382</sup> These mechanisms explicitly include (1) decoupling, (2) performance-based rates, (3) formula rates, (4) multiyear rate plans, and (5) a combination of the above.<sup>383</sup> These mechanisms may be used to recover both capital costs and expenses to provide service as is presently done.<sup>384</sup>

House Bill 1782 gives the PA PUC six months from the bill's effective date to establish specific procedures for approving an application for alternative rates.<sup>385</sup> Although the Proposed Policy Statement Order was issued prior to the passage of House Bill 1782, the PA PUC will be able to issue a final policy statement and associated procedures, now that its authority has been more clearly established by the Legislature.

The PA PUC's proposed policy statement invites utilities to propose base rate structures that:

- promote Federal and State policy objectives (such as conservation);
- reduce disincentives associated with promoting those objectives;
- provide incentives to promote economic efficiency;
- avoid future capital investments; and
- ensure that utilities earn adequate revenue to safely and reliably operate their distribution systems.<sup>386</sup>

The PA PUC also proposes that alternative ratemaking methodologies should demonstrate well-founded cost of service principles, establish a just and reasonable rate structure, and consider impact to customers.<sup>387</sup> Included as part of the proposed policy statement are a list of considerations that the PA PUC will take into account when reviewing a utility's rates and proposed rate structures.<sup>388</sup>

The PA PUC is accepting comments and reply comments on its proposed policy statement until late August and late September, respectively.<sup>389</sup>

#### *D. Application of Laurel Pipe Line Co., L.P.*

On November 14, 2016, Laurel Pipe Line Company (Laurel) filed an Application with the PA PUC proposing to reverse the pipeline's directional flow for

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381. Proposed Policy Statement Order, *Fixed Utility Distribution Rates Policy Statement*, Docket No. M-2015-2518883, (Pa. Pub. Util. Comm'n, June. 23, 2018).

382. 66 Pa. C.S. § 1330 (2018).

383. *Id.* at § 1330(b).

384. Marie Cusick, *New Pennsylvania Law to Create More Revenue Options for Utilities*, ENERGY NEWS NETWORK (June 29, 2018), <https://energynews.us/2018/06/29/northeast/new-pennsylvania-law-to-create-more-revenue-options-for-utilities/>.

385. 66 Pa. C.S. § 1330(d) (2018).

386. Proposed Policy Statement Order, *supra* note 381, at 27.

387. *Id.* at 29.

388. *Id.* at 30.

389. *Id.* at 35-36.

the ninety-mile segment between Pittsburgh and Altoona.<sup>390</sup> The Laurel Pipeline transports mostly gasoline and diesel fuels across the state from Philadelphia area through Western Pennsylvania.<sup>391</sup> The pipeline was installed in 1957.<sup>392</sup> Since then, it has always flowed in a westerly direction.<sup>393</sup> It is presently the only pipeline carrying finished petroleum products (mostly gasoline and diesel fuels) into Western Pennsylvania from refineries and other supply sources on the East Coast.<sup>394</sup> Laurel has recently requested to reverse the line's directional flow to benefit Midwest refineries seeking to ship their products eastward.<sup>395</sup>

In support of its Application, Laurel and supporting intervenor Husky Marketing and Supply Company stated that the proposed reversal would reduce gasoline prices for Pennsylvania customers.<sup>396</sup> Refineries, fuel wholesalers, other market participants intervened in the proceeding and to oppose the Application on the grounds that the proposed reversal would increase fuel prices and cause layoffs by certain businesses.<sup>397</sup>

On March 29, 2018, a PA PUC administrative law judge issued a decision recommending that the Commission deny Laurel's Application.<sup>398</sup> The decision found that Laurel did not provide sufficient supports for its statement that the proposed reversal would decrease retail fuel prices for consumers.<sup>399</sup> The decision also determined that the reversal would have eliminated a major western distribution route.<sup>400</sup>

On July 12, 2018, the PA PUC entered a Final Order affirming the recommendation to deny the Application.<sup>401</sup>

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390. Kathleen E. Carey, *Buckeye sidesteps PUC, reverses Laurel Pipeline*, DELCO TIMES (Apr. 6, 2018), [https://www.delcotimes.com/business/buckeye-sidesteps-puc-reverses-laurel-pipeline/article\\_8ebdfec3-8ee6-5f52-836d-dcb2ed90480e.html](https://www.delcotimes.com/business/buckeye-sidesteps-puc-reverses-laurel-pipeline/article_8ebdfec3-8ee6-5f52-836d-dcb2ed90480e.html).

391. *About the Issue – Reversing the Laurel Pipeline is: Bad for Consumers, Bad for Workers, Bad for Pennsylvania, Good for Buckeye Partners, Good for Out-Of-State Refiners*, <https://www.denybuckeye.com/about-the-issue/> (last visited Oct. 15, 2018) [hereinafter *Reversing the Laurel Pipeline*].

392. *Id.*

393. *Id.*

394. *Id.*

395. *Id.*

396. *Reversing the Laurel Pipeline*, *supra* note 391.

397. *Id.*

398. Recommended Decision, *Application of Laurel Pipeline Company, L.P. for approval to change direction of petroleum products transportation service to delivery points west of Eldorado, Pennsylvania*, Docket No. A-2016-2575829 et al. (Pa. Pub. Util. Comm'n, March 21, 2018).

399. *Id.* at 167.

400. *Id.* at 199.

401. *Id.* at 116.

### E. *A Guide to Utility Rate Making*

On May 17, 2018, the PA PUC announced its updated publication of “A Guide to Utility Ratemaking.”<sup>402</sup> This handbook is designed to introduce ratemaking to customers and new practitioners.<sup>403</sup> It is also a research tool for more advanced users.<sup>404</sup> This handbook is an update to the earlier 1983 publication and addresses “distribution system improvement surcharge, fully projected future test year, and revenue decoupling.”<sup>405</sup> The handbook also features updated industry descriptions that have changed over the years due to competition and other variables and includes a “thorough guide to the procedures used by the Commission to set rates.”<sup>406</sup> This new version of the handbook was created to accommodate changes in the “economy, technology, the state of utility infrastructure and the art of regulation.”<sup>407</sup>

## XVI. UTAH

### A. *Wind and Transmission Proposal*

On June 30, 2017, PacifiCorp d/b/a Rocky Mountain Power (RMP) filed an application for approval of the acquisition of new Wyoming wind resources with a total capacity of 860 MW and construction of new transmission facilities, which were mutually dependent on one another, under provisions of the Utah Code that would preapprove the new assets.<sup>408</sup> Because RMP has indicated it will not file a general rate case before 2020, it also asked for approval of a new Resource Tracking Mechanism (RTM).<sup>409</sup>

Because RMP had not issued its request for proposal (RFP) until after the application was filed and because RMP had not included any need for the capacity in its initial Integrated Resource Plan (IRP), one consumer group filed a motion to stay, which was joined by other parties, and several rounds of testimony and updated supplemental filings were necessary.<sup>410</sup> RMP went from 860 MW new wind

402. James H. Cawley & Norman J. Kennard, *A Guide to Utility Ratemaking*, PA PUC (May 17, 2018), [http://www.puc.pa.gov/General/publications\\_reports/pdf/Ratemaking\\_Guide2018.pdf](http://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf).

403. *Id.* at i.

404. *Id.*

405. Press Releases, Pennsylvania Public Utility Commission, PUC Announces Availability of Updated Utility Ratemaking Guide (May 17, 2018), [http://www.puc.pa.gov/about\\_puc/press\\_releases.aspx?ShowPR=4035](http://www.puc.pa.gov/about_puc/press_releases.aspx?ShowPR=4035).

406. *Id.*

407. *Id.*

408. Transmittal Letter, *Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40, at 1-2 (Pa. Pub. Util. Comm’n, June 30, 2018).

409. *Id.* at 2-3.

410. *Id.*; *Utah Industrial Energy Consumers’ Motion to Stay Proceedings*, Docket No. 17-035-40, (Pa. Pub. Util. Comm’n, Sept. 22, 2017); Supplemental Direct and Rebuttal Testimony filed by RMP, Docket No. 17-035-40 (Pa. Pub. Util. Comm’n filed Jan. 16, 2018); Motion to Vacate Remaining Schedule, Docket No. 17-035-40 (Pa. Pub. Util. Comm’n filed Jan. 19); Order Granting Motion to Vacate Remaining Schedule and Amended Scheduling Order, Docket No. 17-035-40 (Pa. Pub. Util. Comm’n issued Feb. 13, 2018); Second Supplemental Direct Testimony filed by RMP, Docket No. 17-035-40 (Pa. Pub. Util. Comm’n filed Feb. 21, 2018); RMP’s corrected Second Supplemental Direct Testimony, Docket No. 17-035-40 (Pa. Pub. Util. Comm’n filed Feb. 23,

to 1170 MW, then to 1311 MW, and finally, two weeks before hearing, to 1150 MW.<sup>411</sup>

The Division of Public Utilities, Office of Consumer Services, Utah Association of Energy Users, and Utah Industrial Energy Consumers all opposed the proposal.<sup>412</sup> After a four-day hearing, the Utah Public Service Commission (PSC) approved RMP's request for the new wind and transmission resources but denied the request for a rate tracking mechanism.<sup>413</sup>

### B. Residential Net Metering Evaluation

On September 29, 2017, the Public Service Commission approved a settlement concerning RMP's net metering program.<sup>414</sup> The Settlement (1) prohibits new customers from entering the program after November 15, 2017; (2) allows existing net metering customers to remain in the program through December 31, 2035; (3) creates a transition program for customers who submit an interconnection application prior to a cap being reached; (4) fixes the compensation that transition program customers receive for energy exported back to the grid; (5) establishes new tiered interconnection fees; (6) allows RMP to recover a portion of the energy payments it makes to the transmission program customers; and (7) sets proceedings to determine the metrics for the post-transition net metering program.<sup>415</sup>

### C. Treatment of the TCJA

On December 21, 2017, the Utah PSC issued a Notice of Comment Period opening several dockets to investigate the revenue requirement impacts of the TCJA.<sup>416</sup> The Utah PSC ordered the Utah regulated utilities to file written comments describing in detail the impacts of the TCJA on their respective revenue requirement.<sup>417</sup>

In Docket No. 17-035-69, RMP established a regulatory deferred account for the accumulation of customer benefits.<sup>418</sup> RMP was ordered to refund customers

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2018); Division of Public Utilities' Objection to the completeness of Rocky Mountain Power's Filing, Docket No. 17-035-40 (Pa. Pub. Util. Comm'n filed Mar. 9, 2018); Joint Motion to Strike the Surrebuttal Testimony of Rocky Mountain Power, Docket No. 17-035-40 (Pa. Pub. Util. Comm'n filed May 25).

411. Joint Motion to Strike Motion to Strike the Surrebuttal Testimony of Rocky Mountain Witnesses and Expedited Treatment, *Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40 (Pa. Pub. Util. Comm'n, May 25, 2018).

412. See generally Docket No. 17-035-40, <https://psc.utah.gov/2017/06/23/docket-no-17-035-40/>.

413. Order, *Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision*, Docket No. 17-035-40 at 1 (Pa. Pub. Util. Comm'n, June 22, 2018).

414. Order Approving Settlement Stipulation, *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's net Metering Program*, Docket No. 14-035-114, (Pa. Pub. Util. Comm'n, Sept. 29, 2017).

415. *Id.* at 4-6.

416. Notice of Comment Period, *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018,"* Docket Nos. 17-035-69 et al., (Pa. Pub. Util. Comm'n, Dec. 21, 2017).

417. *Id.*

418. Order Granting Motion for Deferred Accounting Order and Notice of Scheduling Conference, *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An act to provide for*

\$61 million for 2018, starting May 1, 2018 through December 31, 2018, and each year thereafter until the next rate case.<sup>419</sup> The balance of the revenue requirement over-collection, which has now been determined to be approximately \$92 million and disposition of the EDIT has been set for further proceedings.<sup>420</sup> RMP made its updated filing June 15 and hearings are set for October.<sup>421</sup>

In Docket No. 17-056-26, Dominion Energy established a regulatory deferred account for the accumulation of customer benefits, and entered into a settlement agreement.<sup>422</sup> Under the agreement, Dominion will return to customers the revenues collected by Dominion in excess of the 21% tax rate, using a surcredit based on each customer class's proportion of the total base distribution non-gas revenues.<sup>423</sup> For August 1, 2018 through July 31, 2019, Dominion will provide an additional tax-related surcredit, to be applied as 12 monthly credits to customers' bills to return to customers the excess income taxes collected by Dominion from January 1, 2018 through May 31, 2018, plus carrying charges.<sup>424</sup> By the end of 2019's first quarter, Dominion must file a report detailing its estimates of all impacts of the TCJA on EDIT.<sup>425</sup>

## XVII. WEST VIRGINIA

### A. *Pleasants Plant Transfer from AE Supply to Monongahela Power Company*

On March 7, 2017, Mon Power and The Potomac Edison Company, FirstEnergy's operating companies in West Virginia, filed a joint petition for approval to acquire the Pleasants coal-fired generating facility in Pleasants County, West Vir-

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*reconciliation pursuant to titles II and V of the concurrent resolution of the budget for fiscal year 2018*", Docket No. 17-035-69 (Pa. Pub. Util. Comm'n, Feb. 28, 2018).

419. Order, *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018,"* Docket No. 17-035-69 (Pa. Pub. Util. Comm'n, Apr. 27, 2018).

420. *Id.*; Rocky Mountain Power's Supplemental Filing and Final Report, Docket No. 17-035-69, at 4 (Pa. Pub. Util. Comm'n, June 15, 2018); Scheduling Order, Notice of Technical Conference, and Notice of Hearing, Docket No. 17-035-69 (Pa. Pub. Util. Comm'n, June 25, 2018).

421. Scheduling Order, Notice of Technical Conference, and Notice of Hearing, *supra* note 420; Rocky Mountain Power's Supplemental Filing and Final Report, *supra* note 420, at 4.

422. Order Granting Motion for Deferred Accounting Order and Notice of Scheduling Conference, *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018,"* Docket No. 17-057-26 (Pa. Pub. Util. Comm'n, Feb. 21, 2018).

423. Order Approving Tariff Revisions, *Investigation of Revenue Requirement Impacts of the New Federal Tax Legislation Titled: "An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018,"* Docket No. 17-057-26 at 1 (Pa. Pub. Util. Comm'n, July 30, 2018).

424. *Id.*

425. Settlement Stipulation, *Application of Dominion Energy Utah to Provide the Impacts of the New Federal Legislation Titled: "An Act to Provide for the Reconciliation Pursuant to Titles II and V of the Budget for Fiscal Year 2018,"* Docket No. 17-057-26, at 4 (Pa. Pub. Util. Comm'n, May 16, 2018).

ginia from a competitive affiliate, Allegheny Energy Supply Company (AE Supply).<sup>426</sup> Mon Power and PE contended that Mon Power's selection of Pleasants arose from a competitive RFP, that ownership of Pleasants had a substantial positive net present value over the review horizon as compared with PJM market purchases of capacity, and that acquiring Pleasants would avoid AE Supply's likely closure of the facility.<sup>427</sup> Opponents argued that the transaction is "risky" and that approving it could have potential adverse rate and regulatory impacts.<sup>428</sup>

After the FERC rejected the Mon Power/AE Supply application for Pleasants, the West Virginia Commission approved the transfer subject to several conditions.<sup>429</sup> The Commission found that because Mon Power and PE expressed confidence in their positive NPV projection, they should accept some cost responsibility if Pleasants performed poorly vis-à-vis the PJM market.<sup>430</sup> Among other safeguards, the Commission required a guarantee that Mon Power and PE would compensate customers during any year that Pleasants energy and capacity revenues fell below the full Pleasants revenue requirements, also allowing a true-up mechanism allowing the companies to recover those compensation amounts from positive margins in subsequent years.<sup>431</sup> The Commission also imposed protections for customers against potential liabilities associated with an impoundment and dam serving the plant, including "an indemnity agreement with a qualified FirstEnergy corporate entity."<sup>432</sup> On February 5, 2018, Mon Power and PE advised the West Virginia Commission that Mon Power and AE Supply would not seek rehearing of the FERC order, and that the transaction would not occur.<sup>433</sup>

### B. *Effects of the TCJA on Investor-Owned Utilities*

The TCJA will have a substantial impact on certain utilities subject to Commission jurisdiction, including electric, gas, water, sewer and solid waste facilities.<sup>434</sup> The West Virginia Commission initiated a proceeding to investigate the Act's effects of the TCJA on utility revenue requirements.<sup>435</sup> The Consumer Advocate Division and a group of industrial intervenors proposed that any benefits to ratepayers should not be unnecessarily delayed.<sup>436</sup> Some utilities cautioned against flowing back the benefits of "excess" accumulated deferred income tax balances

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426. Petition for Approval of a Generation Resource Transaction and Related Relief, *Monongahela Power Co. & the Potomac Edison Co.*, Case No. 17-0296-E-PC, at 1 (W. Va. Pub. Serv. Comm'n, Jan. 26, 2018) [hereinafter *Monongahela Petition for Approval*].

427. *Id.* at 4.

428. *Id.* at 8 (citing WVEUG position).

429. *Monongahela Power Co. and Allegheny Energy Supply Co., LLC*, 162 F.E.R.C. ¶ 61,105 (Jan. 12, 2018).

430. *Monongahela Petition for Approval*, *supra* note 426, at 48.

431. *Id.* at 48-49.

432. *Id.* at 58.

433. Letter from Monongahela Power Company and The Potomac Edison Company to the Public Service Commission of West Virginia re: Petition for Approval of Generation Resource Transaction and Related Relief, Case No. 17-0296-E-PC (Feb. 5, 2018).

434. PL 115-97 (HR 1) (Dec. 22, 2017), 131 Stat 2054.

435. General Order No. 236.1, *In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act* (June 22, 2018) (W. Va. Pub. Serv. Comm'n, Jan. 3, 2018).

436. *Id.*

more quickly than the amortization periods specified under the Act, and they contended that more time would be needed to re-measure the excess ADITs and develop appropriate amortization periods.<sup>437</sup> Several utilities also sought to retain the “stub period” tax expense between the Act’s effective date and the date utilities would be required to flow back the prospective savings arising from the Act.<sup>438</sup> This matter is pending, with post-hearing briefs due in August 2018.<sup>439</sup>

### *C. Levelized Avoided Cost Rate Ceiling and Pass-Through in Future Proceedings*

American Bituminous Power Partners, L.P. (Ambit), a PURPA qualifying facility operating a waste-coal project in Grant Town, West Virginia, sought to amend its electric energy purchase agreement (EEPA) with Mon Power to increase the capacity portion of the EEPA rate, and Mon Power sought authority to pass through in rates the higher incremental costs to utility customers.<sup>440</sup> The request was the latest in a series of filings to set and then modify the Commission’s initial avoided cost rate determination for the EEPA.<sup>441</sup> The Commission concluded that the \$40 per MWh capacity rate proposed in the EEPA revision would exceed the existing avoided cost rate and thus result in rates that are not just and reasonable under PURPA regulations.<sup>442</sup> The avoided cost ceiling is not subject to future modification to accommodate AmBit’s cash flow needs, the Commission found, and PURPA prohibits the Commission from burdening Mon Power and PE ratepayers with QF operating costs that exceed the Commission recognized all-in levelized avoided cost ceiling.<sup>443</sup> However, the Commission calculated a fixed capacity rate adjustment that could be justified by its calculated “all-in levelized avoided cost rate ceiling” of \$52.74 per MWh, and essentially invited Ambit and Mon Power to develop an acceptable rate by altering the fixed capacity rate and eliminating a “Tracking Account” established in 1987.<sup>444</sup> The Commission’s decision was appealed to the West Virginia Supreme Court of Appeals, where the Sierra Club contends that the Commission erred in its determination of just and reasonable rates under the Commission’s own regulations implementing PURPA.<sup>445</sup>

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437. Tax Act Section 13001(d)(4) of the TCJA provides that if an excess reserve is reduced more rapidly or to a greater extent than the reserve would be reduced under the ARAM, (1) the taxpayer’s tax for the taxable year will be increased by the amount by which it reduces its excess tax reserves more rapidly than permitted under a normalization method of accounting; and (2) the taxpayer would not be treated as using a normalization method of accounting for purposes of Sections 168(f)(2) and (i)(9)(C) of the Internal Revenue Code.

438. General Order No. 236.1, *In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act* (W. Va. Pub. Serv. Comm’n, Mar. 8, 2018).

439. *Id.*

440. *Am. Bituminous Power Partners, L.P. & Monongahela Power Co.*, Docket No. 17-0631-E-P, at 2 (W. Va. Pub. Serv. Comm’n, May 3, 2018).

441. *Id.* at 4-7.

442. *Id.* at 24-25; *see also* 18 C.F.R. § 292.304; Rule 12.6. of the Commission *Rules for the Government of Electric Utilities*, 150 C.S.R. 3 (*Electric Rules*).

443. *Am. Bituminous Power Partners, L.P.*, *supra* note 440, at 24.

444. *Id.* at 23; *see also id.* at 3 (development of tracking account).

445. *Sierra Club v. Public Serv. Comm. of W. Va.*, Case No. 18-0513 (W. Va. S. Ct. App. 2018), Pet. Br. at 20, <http://www.courtswv.gov/supreme-court/calendar/2018/briefs/oct18/18-0513petitioner.pdf>.

#### D. Infrastructure Replacement Charges

In 2015, the West Virginia Legislature authorized the Commission to approve infrastructure replacement and expansion plans for gas LDCs, providing for contemporaneous recovery of projected capital costs for certain infrastructure investments.<sup>446</sup> Since then, West Virginia's larger gas utilities have taken advantage of the "Senate Bill 390" provisions to request and receive infrastructure surcharges, and West Virginia-American Water (WVAW), the State's largest private water utility, has received comparable treatment under its Commission-authorized "Distribution System Improvement Charge" (DSIC).<sup>447</sup>

In July 2017, Mountaineer Gas Company filed its annual surcharge request, including its first "true-up" calculation of qualifying investments and surcharge revenues from the first year of the program.<sup>448</sup> The application revised Mountaineer's five-year plan to invest \$94.8 million, including \$24.3 million in 2018, exclusive of a \$30 million proposed expansion projected in the Eastern Panhandle.<sup>449</sup> Mountaineer's 2018 "IREP Rate Component" took into account a 2016 over-recovery of \$124,357.<sup>450</sup> Under the 2018 IREP Rate Component, a typical residential customer would see an increase of approximately \$1.43 per month.<sup>451</sup>

In July 2017, Hope Gas, Inc. filed its annual IREP.<sup>452</sup> Hope proposed an investment of \$31.2 million in 2018.<sup>453</sup> In October 2017, the Commission affirmed a prior decision on the application of a "depreciation expense offset" to the calculation of qualifying rate base, requiring Hope to identify each revenue producing investment project and indicate in its next filing whether the revenue producing investment is qualifying or not.<sup>454</sup>

In May 2017, Bluefield Gas Company filed its IREP for 2018.<sup>455</sup> Bluefield requested approval of its revised five-year plan with a proposed rate increase, "effective on October 1, 2017, and a decrease, effect March 1, 2018," the date on which it then expected that new rates from its pending base rate case would go into effect, and previous qualifying rate base would be rolled into base rates.<sup>456</sup>

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446. W. Va. Code § 24-2-1k (West 2018).

447. *Id.*

448. Infrastructure Replacement and Expansion Program filing for 2018, *Mountaineer Gas Co.*, Case No. 17-1066-G-390P (W. Va. Pub. Serv. Comm'n, Oct. 30, 2017).

449. PUB. SERV. COMM'N OF W. VA., 2017 MANAGEMENT SUMMARY REPORT AND THE ELECTRIC AND GAS UTILITIES SUPPLY-DEMAND FORECAST FOR 2018-2027, 24 (2018) [hereinafter 2017 MANAGEMENT SUMMARY REPORT].

450. *Id.*

451. *Id.*

452. Surcharge on Gas Infrastructure Improvements, *Hope Gas, Inc.*, 17-0685-G-390P, (W. Va. Pub. Serv. Comm'n, Aug. 4, 2017).

453. 2017 MANAGEMENT SUMMARY REPORT, *supra* note 449, at 25.

454. *Id.*

455. *Id.*; Order, *Bluefield Gas Co.*, Case No. 17-0546-G-390P (W. Va. Pub. Serv. Comm'n, Mar. 2, 2018).

456. 2017 MANAGEMENT SUMMARY REPORT, *supra* note 449, at 25.



Bluefield “planned to invest approximately \$7.5 million in infrastructure replacement and system upgrades between 2018 and 2022, with \$2.3 million of that in 2018.”<sup>457</sup> Bluefield was allowed to implement its requested rates.<sup>458</sup>

In June 2017, WVAW filed a petition seeking approval of a proposed DSIC.<sup>459</sup> WVAWC proposed investing approximately \$29.9 million in DSIC facilities during 2018 and requested an increase of \$2.96 million, or 2.19% over current rates.<sup>460</sup> In December 2017, the Commission approved a Joint Stipulation in which the parties agreed that the Commission should allow a recovery of \$4.3 million through the DSIC surcharge, primarily for investments in main replacement.<sup>461</sup>

*E. PSC denial of APCo wind acquisition*

In July 2017, Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) filed a Petition for Commission consent and approval for APCo to enter into certain transactions to acquire, after completion of construction, the Hardin wind generation facility and the Beech Ridge II wind generation facility.<sup>462</sup> The Commission denied APCo’s petition.<sup>463</sup> It agreed with the Virginia State Corporation Commission that APCo did not prove a need for the capacity or demonstrate that the wind facilities are needed to address an energy deficiency.<sup>464</sup>

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457. *Id.*

458. *Id.*

459. Order, *W. Virginia-Am. Water Co.*, Case No. 17-0466-W-CN, at 2 (W. Va. Pub. Serv. Comm’n, Aug. 10, 2017).

460. *Id.*

461. *Id.* at 3.

462. Initial Brief of Commission Staff, *Appalachian Power Co. & Wheeling Power Co.*, Case No. 17-0894-E-PC (W. Va. Pub. Serv. Comm’n, May 30, 2018).

463. *Id.* at 18.

464. *Id.* at 17-18.

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