REPORT OF THE RENEWABLE ENERGY & DEMAND-SIDE MANAGEMENT COMMITTEE

This report summarizes a selection of federal and state legislative, regulatory, and judicial developments in renewable energy and demand-side management during 2009.[*] Separate sections in the renewable energy portion of this report describe hydrokinetic and off-shore wind developments, each of which involve significant coordination between federal and state governments.

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I. RENEWABLE ENERGY DEVELOPMENTS

A. Federal Government Activity

1. Pending and Enacted Federal Legislation

On February 17, 2009, President Obama signed the American Recovery and Reinvestment Act of 2009 (ARRA), a package of spending and tax measures intended to stimulate the economy and create or save jobs.[1] The ARRA provided $787 billion in direct government spending or tax cuts: of that amount, about $65 billion was directed to various energy-related initiatives, including tax code changes and other provisions intended to stimulate increased development of renewable energy resources.

1. American Recovery and Reinvestment Act of 2009 (ARRA), Pub. L. No. 111-5, § 123, 123 Stat. 115 (2009).

2. Tax Incentives

The ARRA included several renewable energy tax incentives. First, it extended the Production Tax Credit (PTC) for electricity produced from certain renewable energy resources.[2] This extension moved the required in-service dates to claim the PTC to December 31, 2012 for wind power facilities, and to December 31, 2013 for other qualifying renewable energy facilities (including biomass, geothermal, incremental hydropower, landfill gas, waste-to-energy, and tidal and wave facilities).

The ARRA also created new tax incentives for renewable energy facilities. For example, the bill allows renewable energy facility owners to claim a one-time Investment Tax Credit (ITC) in lieu of the PTC.[3] Like the long-term PTC extension, the ITC requires an in-service date of December 31, 2012 for wind facilities and of December 31, 2013 for other renewable energy facilities to claim its benefits.

To provide developers without enough income to benefit from tax credits the opportunity to capture similar incentives, the bill also created a new program within the Department of the Treasury that gives renewable energy facility owners the option to receive a cash grant up front in lieu of claiming either a PTC or ITC.[4] Generally, the grants are equal to thirty percent of the cost of the facility (although in some cases, grants are equal to ten percent of the cost of the facility), and will be issued within sixty days of the date the facility is placed in service or within sixty days of the date Treasury receives the grant application, if later. To be eligible for a grant, facilities must be either be placed in service during 2009 or 2010, or begin construction in 2009 or 2010 and be placed in service before the date the PTC and ITC would expire for the particular renewable resource type constructed.

Other tax incentives in the ARRA aimed at developing renewable and alternative energy included an increase in the available tax credits for alternative fuel filling stations, such as hydrogen refueling stations,[5] an increase in the tax credit for plug-in electric drive vehicles,[6] and a new ITC for facilities and properties used to manufacture advanced energy equipment, including items such as wind turbines, solar panels, plug-in hybrid vehicles, fuel cells, etc.[7]

3. Loan Guarantees

The ARRA also established a new temporary six billion dollar Department of Energy (DOE) loan guarantee program intended to boost near-term development of renewable energy projects.[8] This program, which was created through a temporary amendment to the existing "Innovative Technology Loan Guarantee Program" under Title XVII of the Energy Policy Act of 2005,[9] allows

2. ARRA § 1101, 123 Stat. at 319.

3. ARRA § 1102, 123 Stat. at 319-20.

4. ARRA § 1603, 123 Stat. at 364-66.

5. ARRA § 1123, 123 Stat. at 325.

6. ARRA §§ 1141-43, 123 Stat. at 326-32.

7. ARRA § 1123, 123 Stat. at 325; ARRA §§ 1141-43, 123 Stat. at 326-32; ARRA § 1302, 123 Stat. at 345-48.

8. ARRA, 123 Stat. at 140.

9. Innovative Technology Loan Guarantee Program, 42 U.S.C. § 16511 (2006).

DOE to pay the cost of loan guarantees for new renewable energy systems (including new incremental hydropower), electric power transmission systems (both new lines and upgrades to existing lines), and "leading edge" biofuel pilot or demonstration projects up to a maximum of five hundred million dollars.[10] With regard to electric transmission projects, the statute lists several factors that DOE may take into account when considering whether to guarantee a particular project, including the viability of the project without a guarantee, the availability of other government incentives, the importance of the project in meeting reliability needs, and the role of the project in meeting state or regional environment and climate change goals.[11] Any project guaranteed under this provision must commence construction no later than September 30, 2011.

4. Proposed National Renewable Energy and Energy Efficiency Resource Standards

Although not enacted, comprehensive energy and climate legislation made significant advancements in Congress during 2009. The American Clean Energy and Security Act of 2009, a comprehensive energy and climate measure, known as the "Waxman-Markey" bill, passed the House of Representatives in late June,[12] while the American Clean Energy and Leadership Act of 2009, a stand-alone energy bill, passed the Senate Energy and Natural Resources Committee in July.[13]

Both of these bills included a combined nationwide Renewable Energy and Energy Efficiency Resource Standard for retail electricity suppliers that sell more than four million megawatt hours (MWh) per year. Similar to a State renewable portfolio standard (RPS), this national standard would require utilities to provide a certain percentage of the electricity they supply from renewable energy sources and "energy efficiency resources" (including demand response, reduced demand from lighting, heating and cooling and other efficiency measures, etc.). The American Clean Energy and Security Act of 2009 would adopt a standard of twenty percent by 2021 (with increased percentages in later years), of which one quarter (five percent) could be met with energy efficiency resources.[14] The American Clean Energy Leadership Act of 2009 would enact a standard of fifteen percent by 2021 (again with increasing percentages in later years), of which 26.67 percent could be met with energy efficiency.[15] Each measure identifies a specific list of renewable energy sources and energy efficiency resources that could satisfy the standard. The American Clean Energy and Security Act of 2009 would give the FERC responsibility for managing compliance with this standard, while the American Clean Energy Leadership Act of 2009 would charge the DOE with this task.

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10. ARRA § 406, 123 Stat. at 145 (enacting a new § 1705 of the Energy Policy Act of 2005).
11. *Id.*
12. American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009).
13. American Clean Energy and Leadership Act of 2009, S. 1462, 111th Cong. (2009).
14. H.R. 2454 § 101 (2009).
15. S. 1462 § 132 (2009).

5. FERC Actions

a. Transmission Rate Incentives for Renewable Energy Interconnections

During 2009, the FERC continued to encourage the transmission of renewable power from remote locations to load centers by providing rate incentives to transmission providers under the procedures established in Order 697.[16] That order implemented Section 219 of the Federal Power Act (FPA),[17] which allows public utilities to obtain incentive-based rate treatment for transmission facilities that either ensure reliability or reduce the cost of delivered power by reducing congestion. *Tallgrass Transmission, L.L.C. and Prairie Wind, L.L.C.*,[18] issued at the tail end of 2008, became a template for applying the procedures of Order 697 to projects specifically intended to facilitate the transfer of significant levels of renewable generation to load. In *Pioneer Transmission, L.L.C.*,[19] the Commission granted the applicant a number of requested rate incentives for a 765 kV transmission line in Indiana that will connect the PJM Interconnection, LLC (PJM) and Midwest Independent Transmission System Operator, Inc. (MISO) and will enable the interconnection of over 4,000 MW of new wind resources. The rate incentives granted by the FERC were: (1) a base return on equity (ROE) of eleven percent, with an adder of fifty basis points for participation in PJM and MISO effective upon Pioneer's membership and placing its transmission facilities under their control and another 150 basis points for investment in new transmission, given the risks involved in the $1 billion project; (2) the inclusion of 100% of construction work in progress (CWIP) in rate base during the development and construction period of the project; (3) recovery of 100% of prudently incurred costs in the event that the project was abandoned for reasons outside of Pioneer's control; and (4) creation of a regulatory asset for pre-commercial costs on which the applicant could accrue carrying costs, subject to proving that such costs were just and reasonable. The FERC denied Pioneer's request for an additional ROE incentive of fifty basis points for using new advanced transmission technologies on the ground that the technologies proposed had been in use for many years. On rehearing, the FERC clarified that its decisions regarding the rate incentives did not prejudge the determinations required to be made through the regional transmission planning process.[20]

The FERC applied the same rationale in *Green Power Express, L.P.*,[21] in which it approved a rate incentive for one of the largest single transmission projects ever developed in the United States, 3,000 miles of transmission lines, costing $10-$12 billion, to bring 12,000 MW of wind energy and stored energy

16. *Promoting Transmission Investment Through Pricing Reform*, 119 F.E.R.C. ¶ 61,062 (2007); Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006) (to be codified at 18 C.F.R. pt 35 (2006)); Order No. 679-A, 72 Fed. Reg. 1,152 (Jan. 10, 2007) (to be codified at 18 C.F.R. pt. 35 (2007)).

17. 16 U.S.C. § 824 (2006).

18. *Tallgrass Transmission, L.L.C.*, 125 F.E.R.C. ¶ 61,248 (2008), *reh'g pending*.

19. *Pioneer Transmission, L.L.C.*, 126 F.E.R.C. ¶ 61,281 (2009), *order granting clarification and denying rehearing*, 130 F.E.R.C. ¶ 61,044 (2010).

20. *Pioneer Transmission, L.L.C.*, 130 F.E.R.C. ¶ 61,044 (2010).

21. *Green Power Express, L.P.*, 127 F.E.R.C. ¶ 61,031 (2009).

from the Dakotas, Minnesota, and Iowa to Midwest load centers in Chicago, southeastern Wisconsin, and Minneapolis. In addition to the incentives[22] granted to Pioneer, the FERC granted Green Power a hypothetical capital structure of sixty percent equity and forty percent debt.[23] Similarly, in *Citizens Energy Corporation*, the FERC allowed a hypothetical capital structure of fifty percent debt, fifty percent equity and a thirty-year levelized capital recovery period.[24]

But the FERC has made it clear that connecting renewable resources alone is not enough to merit incentive rate treatment if the project does not meet the requirements of section 219 of the FPA. In *Southern California Edison Company*[25] and *Green Energy Express, L.L.C.*,[26] the FERC held that, unlike the applicants in *Tallgrass, Pioneer,* and *Green Power,* SoCal Edison and Green Energy Express had not shown that their proposals to interconnect new solar generation would improve reliability or reduce congestion. However, because the projects were under consideration in the California ISO's (CAISO) planning process, The FERC approved the rate incentives conditioned upon the CAISO approving the projects and specifically finding that they would ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[27]

6. Negotiated Rate Authority and Priority Access

The FERC has adopted a flexible approach in evaluating requests for negotiated rate authority to secure financing for merchant transmission lines located outside the footprint of a regional transmission organization. In *Chinook Power Transmission, L.L.C. and Zephyr Power Transmission, L.L.C.*,[28] Chinook and Zephyr proposed to construct two five-hundred (500) kV high voltage direct current transmission lines, one of 1,000 miles originating in Montana and the other of 1,100 miles originating in Wyoming. Each line would transport approximately 3,000 MW of wind power to the Southwestern United States. The FERC took the opportunity to revisit the ten criteria it has developed to guide its analysis of whether negotiated rate authority is just and reasonable for a given merchant project and determined that a refined analysis focused on four areas would be more appropriate, in particular for projects outside a Regional Transmission Organization (RTO)/Independent System Operator (ISO) context. The four areas are:

> (1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements.29 The FERC found that the applicants qualified for negotiated rate authority and required them to file a non-discriminatory Open Access Transmission Tariff (OATT) with firm

22. The FERC granted Green Power incentive ROE adders of 100 basis points for its status as an independent transmission company, 50 basis points for participation in an RTO and 10 basis points in recognition of the size, scope and risks of the project for a total ROE of 12.38T. *Id* at P 77.

23. *Id.* at P 72.

24. *Citizens Energy Corp.*, 129 F.E.R.C. ¶ 61,242 (2009).

25. *Southern Cal. Edison Co*., 129 F.E.R.C. ¶ 61,246 (2009).

26. *Green Energy Express, L.L.C.*, 129 F.E.R.C. ¶ 61,165 (2009).

27. 129 F.E.R.C. ¶ 61,246, at 62,326; 129 F.E.R.C. ¶ 61,165, at 61,885.

28. *Chinook Power Transmission, L.L.C. & Zephyr Power Transmission, L.L.C.,* 126 F.E.R.C. ¶ 61,134 (2009), *order on reh'g,* 128 F.E.R.C. ¶ 61,074 (2009).

29. *Id*. at 61,765.

> tradable secondary transmission rights, meet certain regional reliability requirements and participate in regional planning processes.30

On rehearing, the FERC agreed that Chinook and Zephyr would not need to file an OATT within thirty days of the close of the open season and instead granted them permission to file their OATT within one year of completing their open season.[31] The Commission has since applied its refined four-part analysis to other merchant transmission projects.[32]

Significantly, the FERC allowed Chinook and Zephyr to allocate fifty percent of the capacity in each of the lines to an anchor wind generation customer that had agreed to share initial development costs without holding an open season, conditioned upon holding an open season for the remaining capacity and offering bidders the same rates and terms if the bidders were willing to agree to the same twenty-five-year commitment as the anchor tenant.[33] Similarly, in *Northeast Utilities Service Company and NSTAR Electric Company*,[34] the FERC found that a participant-funded transmission expansion could be allocated 100% to the participant funding the line without an open season and that this did not constitute undue discrimination because any transmission customer has the right to request a transmission service expansion from a transmission-owning utility.[35] The FERC demonstrated further flexibility in *Milford Wind Corridor,*[36] in which it granted a request for a declaratory order confirming Milford's priority right to use the entire capacity of an already-constructed eighty-eight mile line intended to connect a 1,000 MW wind farm being built in five phases and waiving the requirement to file an OATT. However, the FERC refused to grant a "safe harbor" exclusive use period and required Milford to offer firm transmission rights to third parties until it was ready to use the capacity itself and to expand the line's capacity if a third party wanted to use the line and no further capacity was available.[37] If a third party requested service, Milford would also be required to file an OATT within sixty days.[38]

The FERC's flexibility found its limit, however, in *Mountain States Transmission Intertie, L.L.C. and Northwestern Corporation,*[39] where it held that the applicants had not met the four-part test of *Chinook* for negotiated rate authority because of the preferences provided through the parties' affiliate relationship.[40]

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30. *Id.* at 61,770.

31. 128 F.E.R.C. ¶ 61,074 at 61,434 (2009).

32. *See, e.g., Wyoming Colorado Intertie, L.L.C.*, 127 F.E.R.C. ¶ 61,125 (2009) (granting authority to sell transmission rights at negotiated rates).

33. 126 F.E.R.C. ¶ 61,134, at 61,769.

34. *Northeast Utils. Serv. Co. & NSTAR Elec. Co*., 127 F.E.R.C. ¶ 61,179 (2009).

35. *Id.* at 61,831.

36. *Milford Wind Power Corridor, L.L.C.*, 129 F.E.R.C. ¶ 61,149 (2009).

37. *Id.* at 61,638.

38. *Id.* at 61,640.

39. *Mountain States Transmission Intertie, L.L.C. & Northwestern Corp*., 127 F.E.R.C. ¶ 61,270 (2009).

40. *Id.* at 62,353.

7. Integrating Renewable Resources into the Wholesale Electric Grid

The FERC commissioned a new study in May 2009 that will use Frequency Response in assessing the reliability impact of integrating large amounts of wind and other variable resources into the existing grid. The goal of the study, conducted by Lawrence Berkeley National Laboratory (LBNL) and overseen by Commission staff, is to determine whether Frequency Response is an appropriate metric for use in measuring reliability impacts of variable resources. Due to be completed in April or May of 2010, the study will help to inform federal and state energy policy makers about the current limitations of the grid and to identify what new transmission facilities would be needed to reliably accommodate future and planned renewable resources.[41] This assessment follows hard on the heels of another LBNL study funded by the DOE and released in February 2009 which addressed the cost of transmission for energy and reviewed transmission planning studies.[42]

The FERC also sought the views of electric industry participants on transmission planning needed to enhance integration of renewable resources, operational challenges to bulk power system reliability posed by such resources, and innovative solutions. At a March 2009 technical conference on Integrating Renewable Resources into the Wholesale Electric Grid, the Commission heard a wide range of proposals for reforming national transmission policy. Proposals included the need for a National Energy Policy to guide planning,[43] mandatory membership in RTOs for the purposes of transmission planning and cost allocation,[44] and primary siting authority for the FERC.[45] Witnesses described challenges to grid integration ranging from the timing disconnect between the availability in the spring of renewable energy generation and utilities' peak load in the summer, to the need for higher planning reserve margins to maintain grid reliability when intermittent resources are incapable of producing sufficient energy.[46] Participants discussed possible solutions for dealing with these operational challenges, including the integration of wind forecasting[47] and energy storage technologies, and advanced technologies to provide reactive support and voltage regulation, such as static VAR compensators or static synchronous compensators.[48] Presenters described regional,[49] inter-regional,[50]

41. Jon Wellinghoff, FERC Chairman, Remarks at the CAISO Stakeholder Symposium (Oct. 7, 2009).

42. ANDREW MILLS, RYAN WISER & KEVIN PORTER, THE COST OF TRANSMISSION FOR WIND ENERGY: A REVIEW OF TRANSMISSION PLANNING STUDIES (Feb. 2009), *available at* http://eetd.lbl.gov/ea/ems/reports/lbnl-1471e.pdf.

43. Joseph L. Welch, Chairman, President & CEO, ITC Holdings Corp., Comments at the Technical Conference on Integrating Renewable Resources into the Wholesale Electric Grid (Mar. 2, 2009).

44. *Id.* at 5.

45. Elizabeth Anne Moler, Executive Vice President, Exelon Corporation, Remarks at the Tech. Conf. (Mar. 2, 2009) at 2.

46. *Id.* at 4.

47. Rick Gonzales, Vice President of Operations, NYISO, Prepared PowerPoint Presentation at Tech. Conf. (Mar. 2, 2009) at 4-6.

48. Clark W. Gellings, Vice President-Technology, Electric Power Research Inst., Comments at Tech. Conf. (Mar. 2, 2009) at 2 (describing transmission development planning in the West).

49. Pedro J. Pizarro, Executive Vice President of Power Operations, Southern Cal. Edison Co., Prepared Remarks at Tech. Conf. (Mar. 2, 2009) at 2-3.

and joint[51] transmission planning initiatives for transmission development but noted the limitations, including the lack of interconnection-wide planning[52] and the need for harmonization of regional differences in cost allocation methods between RTOs.[53]

B. State Government Activity

1. Northeast

a. Renewable Energy Incentives

The Connecticut Department of Public Utility Control revised its RPS regulations in October 2009 to permit electric suppliers to bank renewable energy certificates (RECs) generated in a particular year for use to satisfy the RPS in either of the two subsequent years.[54] This brings Connecticut's approach to RPS compliance more in line with that of other states in the region.

In June 2009, the Maine legislature passed "An Act to Establish the Community-Based Renewable Energy Pilot Program" (Pilot Program), which provides additional incentives to certain small (under 10 MW) renewable projects that are supported by the municipality in which they are located.[55] Under the Pilot Program, which is limited to a total of 50 MW (25 MW within the service territory of a single investor-owned utility), these community-based renewable projects can elect to sell the energy to state utilities under long term contracts mandated by the statute, or to receive a premium for RECs produced by the projects of 150% of those received by other renewable projects.[56]

In May 2009, the Massachusetts Department of Energy Resources (MA DOER) filed final regulations,[57] which became effective June 2009, implementing RPS changes provided for in the 2008 Green Communities Act.[58] These changes included replacement of the term "New Renewable" in the regulations with "RPS Class I Renewable," and the addition of certain newly eligible Class I resources, including algae as a type of eligible biomass fuel, geothermal energy, marine and hydro-kinetic energy, and hydroelectric energy meeting eligibility requirements.[59] The regulations also set out the requirements for "RPS Class II" resources, which are nearly identical to Class I resources but were brought online on or before December 31, 1997, and also include a new

50. Clair Moeller, Vice President Transmission Asset Management, Midwest ISO, Remarks at Tech. Conf. (Mar. 2, 2009); Lauren Azar, President of the Organization of Midwest ISO States, Comments at Tech. Conf. (Mar. 2, 2009).

51. Michael J. Kormos, Senior Vice President of Operations, PJM Interconnection, L.L.C., Statement at Tech. Conf. (Mar. 2, 2009).

52. Moler, *supra* note 45, at 3-5.

53. Kormos, *supra* note 51, at 15.

54. CONN. AGENCIES REGS. § 16-245a-1 (2009).

55. Pub. L. 329, 124th Legis. (Me. 2009).

56. *Id.*

57. 225 MASS. CODE REGS. 14.00, 15.00 (2009).

58. An Act Relative To Green Communities, 2008 Mass. Acts 169.

59. 225 MASS. CODE REGS. 14.01-14.12 (2009).

category of "Waste Energy" resources.[60] Under the Class II regulations, the minimum standard is 3.6% for all Class II resources, and 3.5% for Waste Energy.

The MA DOER also filed regulations implementing the alternative energy portfolio standard, which requires all retail electricity suppliers to annually provide a percentage of electricity sales from "alternative energy generating sources." [61] These sources include: gasification with capture and permanent sequestration of carbon dioxide; combined heat and power; flywheel energy storage; any facility which substitutes any portion of its fossil fuel source with an equal or greater portion of a DEP-approved, alternative, paper-derived fuel source; energy efficient steam technology; and any other alternative energy technology approved by MA DOER.[62]

In December 2009, the MA DOER announced the addition of a Solar Carve-Out requirement to the Class I RPS, to become effective on January 1, 2010.[63] Solar Carve-Out Generation Units have a maximum capacity of 2MW and a commercial operation date after December 31, 2007.[64] The minimum Solar Carve-Out requirement will be calculated each year based on a formula set forth in the regulations.[65] For 2010, the requirement is estimated to be .0680%, which is part of, not in addition to, RPS Class I minimum standards.[66] The alternative compliance payment is set for 2010 at $600/MWh, and may be reduced by the MA DOER annually, but not by more than ten percent in any year.[67] The MA DOER also announced in December 2009 that it would suspend review of RPS qualification applications for clean wood biomass generating facilities pending development of "sustainability" criteria that will apply to such units.[68]

Legislation passed in New Hampshire in June 2009 clarified requirements of Class IV (small hydro) renewable energy generating facilities.[69]

In December 2009, the New York Public Service Commission (NY PSC) announced expansion of the state's RPS goal from twenty-five percent to thirty percent by 2015.[70] The NY PSC at the same time approved funding for the Main Tier, which includes wind, hydro and biomass resources.[71]

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60. 225 MASS. CODE REGS. 15.01-15.12 (2009). The regulations define "Waste Energy" as "[e]lectrical energy generated from the combustion of municipal solid waste." *Id.* §15.02.

61. 225 MASS. CODE REGS. 16.01-16.12 (2009).

62. *Id.*

63. MASS. DEP'T OF ENERGY RES., SOLAR RPS CARVE-OUT, SOLAR CREDIT CLEARINGHOUSE, FINAL DESIGN DOCUMENT FOR REGULATIONS (Dec. 18, 2009), *available at* http://www.mass.gov/Eoeea/docs/doer/renewables/solar/solar-webinar-2009dec18.pdf.

64. *Id.* at 4.

65. *Id.* at 9.

66. *Id.*

67. *Id.* at 5.

68. Phillip Guidice, Mass. DOER Comm'n, Letter to Massachusetts Biomass Energy Stakeholders (Dec. 3, 2009).

69. An Act Clarifying the Eligibility Requirement for Class IV Renewable Energy Generating Facilities and Relative to Renewable Energy Certificates, H. B. 229 (N.H. 2009).

70. Press Release, N.Y. PSC, PSC Sets Expanded Renewable Energy Goal (Dec. 16, 2009). The Order Establishing New RPS Goal and Resolving Main Tier Issues was issued by the PSC on January 8, 2010 in Docket No. 03-E-0188 (2009).

71. *Id.*

Rhode Island enacted a new Long-Term Contracting Requirement for Renewable Energy in June 2009, which requires each electric distribution company to solicit proposals from renewable energy developers on an annual basis and enter long-term contracts for the purchase of capacity, energy, and attributes from newly developed renewable energy resources.[72] The legislation requires a minimum long-term contract capacity of 90 MW, of which 3 MW must be solar, in-state generation, by 2014.[73]

In May 2009, Vermont adopted the Vermont Energy Act of 2009.[74] The act includes a feed-in-tariff, requiring all retail electric providers to purchase electricity generated by eligible renewable energy facilities through the Sustainably Priced Energy Enterprise Development (SPEED) program via long-term contracts with fixed standard offer rates.[75] SPEED facilities include solar, wind, biomass, and certain hydropower, up to 2.2 MW in capacity, commissioned on or after September 30, 2009.[76] Price paid per kWh will vary depending on technology type.[77]

b. Siting

The Vermont Energy Act of 2009 described above also includes provisions promoting the development of wind energy generation facilities on state lands, including commercial scale projects.[78] The siting of such projects may not directly conflict with specific state or federal law restrictions, and sites must be chosen and developed in a manner that maximizes energy production and minimizes environmental and aesthetic impacts.[79]

2. Mid-Atlantic

a. Renewable Energy Incentives

By Final Order adopted in May 2009, the Pennsylvania Public Utilities Commission revised the state's Alternative Energy Portfolio Standard (AEPS) regulations, as required by statute, to establish procedures and guidelines for low-impact hydropower facilities and generators utilizing by-products of pulping and wood manufacturing processes to follow in order to qualify as AEPS Act Tier I resources.[80] At the same time, it established additional reporting requirements and related procedures that electricity suppliers are required to follow, and procedures that will be employed to increase the AEPS Act non-solar photovoltaic (PV) Tier I percentage requirement on a quarterly basis to account for the newly eligible sources.[81]

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72. An Act Relating to Public Utilities and Carriers, 2009 R.I. Pub. Laws 51.
73. *Id.*
74. The Vermont Energy Act, Vermont H.B. 446, 2009 Vt. Laws 45.
75. *Id.* § 4.
76. *Id.*
77. *Id.*
78. *Id.*
79. *Id.* § 48
80. *P.A. P.U.C.*, *Final Order*, Docket No. M-2009-2093383 (May 28, 2009).
81. *Id.*

Virginia expanded its voluntary renewable energy portfolio goal by legislation passed in March 2009, establishing a goal for investor-owned incumbent electric utilities to have fifteen percent of their total electric energy sales in the base year be from renewable energy sources in calendar year 2025.[82] Previously, utilities were permitted to participate in the voluntary renewable energy portfolio standard program if they could demonstrate a reasonable expectation of achieving twelve percent of its base year electric energy sales from certain renewable energy sources during calendar year 2022. Participating utilities that meet the specified percentage goals are eligible for certain performance incentives.

West Virginia enacted an "Alternative and Renewable Energy Portfolio Standard" in June 2009. The RPS requires investor-owned utilities in the state with more than 30,000 residential customers to supply twenty-five percent of retail electricity sales through eligible renewable and alternative energy sources.[83] "Alternative energy resources" are defined to include coal technology, coal bed methane, natural gas, fuel produced by a coal gasification or liquefaction facility, synthetic gas, integrated gasification combined cycle technologies, waste coal, tire-derived fuel, pumped storage hydroelectric projects, and recycled energy.[84] Although only ten percent of the requirement may be met through use of electricity generated from natural gas, there is no requirement that any minimum portion of the RPS come from renewable resources, which include solar electric, solar thermal, wind, run-of-river hydropower, geothermal energy, fuel cells, and certain biomass. Renewable resource facilities do, however, receive more credits per MWh of electricity generated than alternative energy facilities. Utilities are required to submit compliance plans to the West Virginia Public Service Commission by January 1, 2011 for review and approval.[85]

b. Interconnection

In July 2006, the District of Columbia Public Service Commission (DC PSC) initiated a formal inquiry into the development of uniform interconnection procedures for on-site distributed generation systems. The DC PSC subsequently concluded that an interconnection standard was feasible and continued with rulemaking process, culminating with the adoption of final interconnection regulations in February 2009.[86] The rules apply to all distributed generation systems of 10 MW or smaller that are operated in parallel with the electric distribution system and are not subject to the interconnection requirements of PJM.

82. An Act to Amend and Reenact § 56-585.2 of the Code of Virginia, Relating to the Sale of Electricity from Renewable Sources Through a Renewable Portfolio Standard Program, Virginia H.B. 1994, 2009 Va. Acts 744.

83. The Alternative and Renewable Energy Portfolio Act, W. Va. H.B. 103, 2009 W. Va. Acts 9 (Benchmarks set by the statute are: 10% from 2015 to 2019; 15% from 2020 to 2024; 25% by January 1, 2025).

84. *Id.* at § 24-2F-3.

85. *Id.* at § 24-2F-6.

86. Order No. 15234, *Formal Case No. 1050*, *In the Matter of the Investigation of Implementation of Interconnection Standards in the District of Columbia* (PSC 1050) (Apr. 8, 2009).

3. Mid-West

a. Renewable Energy Incentives

In August 2009, Illinois enacted Senate Bill 2150, which amended the Illinois Power Agency Act of 2007 to require competitive electric suppliers to meet the state's RPS requirements.[87] Previously, the Illinois RPS, which requires the state's electric utilities to get at least twenty-five percent of their power from renewable resources by 2025, applied only to the state's major utilities (Ameren Illinois and Commonwealth Edison).[88] The amendment also added a requirement to the RPS that solar energy constitute at least six percent portion of the electricity supplied by the state's competitive electric suppliers and major utilities by 2015.[89] Municipal electric utilities and electric cooperatives remain exempt from the RPS.

In September 2009, the Illinois Power Agency (IPA) proposed a 2010 power procurement plan for Commonwealth Edison (ComEd) and Ameren Illinois (Ameren) that set a goal of buying 600,000 MWh of renewable energy annually for Ameren and 1.4 million MWh for ComEd. The Illinois Commerce Commission (ICC) approved the plan over opposition by consumer groups and the companies themselves, but required the parties to meet and resolve concerns about the impact of renewable procurements on consumer electric bills.[90]

Illinois also passed legislation in 2009 providing state-backed guarantees for construction of renewable energy and clean coal projects and authorizing funding for renewable energy projects, including technologies improving renewable fuel production, and renewable energy storage.[91]

New rules adopted by Iowa Utilities Board (IUB) became effective in 2009, implementing Iowa's wind energy and renewable energy production tax credits.[92] The amendments set maximum nameplate capacity for eligible applications.[93]

In April 2009, Minnesota passed a comprehensive energy bill extending renewable energy production incentives, including those for hydroelectric facilities, funding renewable energy research, reestablishing and clarifying green energy pricing requirements, and establishing new rules for distributed generation.[94] Additional legislative measures passed in 2009 directed the Minnesota Pollution Control Agency to establish a greenhouse gas (GHG) emissions registry and adopt GHG monitoring rules; standardized small (5 MW or less) renewable resource utility purchase contracts; and ensured that almost $11 million of Renewable Energy Incentive Payments remain available through 2011 for development of wind, hydropower and on-farm biogas.[95]

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87. 2009 Ill. Laws 159.

88. 2009 Ill. Laws 481 (Illinois Power Agency Act).

89. 2009 Ill. Laws 159.

90. Illinois Power Agency, Petition for Approval of Initial Procurement Plan, Final Order of Illinois Commerce Commission, Docket No. 09-373 (Dec. 28, 2009).

91. 2009 Ill. Laws 103, 2009 Ill. S.B. 1906.

92. IOWA CODE ANN. § 476B, 476C (2009).

93. 199 IOWA ADMIN. CODE 15.18 (2010).

94. 2009 Minn. Sess. Law Serv. 110 (West) (Omnibus Energy Conservation Provisions Bill).

95. 2009 Minn. Laws 37; 2009 Minn. Sess. Law Serv. 37 (West).

Rules implementing Ohio's RPS, which was passed by the state General Assembly in 2008, were enacted by the Ohio Public Utilities Commission (Ohio PUC), effective December 2009.[96] The Ohio RPS requires the state's electric utilities to receive at least twenty-five percent of their power from renewable resources by 2025.[97] The Ohio PUC rules provide for annual benchmarks, beginning in 2009, and review by commission staff.

b. Siting

Both Illinois and Wisconsin enacted new laws in 2009 to address renewable energy facility siting issues. In Illinois, the School Solar Wind Generator Act, passed in August 2009, provides incentives for installations of solar and wind power systems on school district facilities and land.[98] In October 2009, Wisconsin enacted a statute requiring the state Public Service Commission (Wisconsin PSC) to promulgate statewide wind energy system siting standards for wind farms under 100 MWs.[99] The Wisconsin PSC already oversees larger wind projects, but currently leaves smaller projects to local governments. The new statewide standards allow limited local control as long as are not more restrictive than the Wisconsin PSC standards. Legislators estimated that over 600 MW of proposed wind projects have been stalled by local permitting requirements.

4. Southwest

a. Renewable Energy Incentives

In May 2009, Nevada enacted Senate Bill 358[100], which increases the state's RPS from a target of twenty percent by 2015 to twenty-five percent by 2025 and increases from five percent to six percent the amount of energy to be generated from solar power.[101] Additionally, the law creates the Renewable Energy and Efficiency Authority to encourage the development of renewable energy facilities within the state and authorizes local governments to create and maintain their own renewable energy projects.[102]

b. Siting

Arizona enacted House Bill 2336 in July 2009, a statute intended to ease the land use entitlement process for renewable energy facilities.[103] Under this law, local governments are permitted to designate "renewable energy incentive districts."[104] As to such districts, if designated, local governments must adopt a "renewable energy incentive plan" to encourage the construction and operation

96. OHIO ADMIN. CODE § 4901:1-40-01 (2009).
97. OHIO REV. CODE § 4928:64 (2009).
98. 2009 Ill. Legis. Serv. 96-843 (WEST).
99. 2009 Wis. Act 40, 2009 Wis. S.B. 185 (2009).
100. 2009 Nev. S.B. 358.
101. *Id.*
102. *Id.*
103. 2009 ARIZ. REV. STAT. 86 §§ 9-499.14, 11-254.07 (LexisNexis 2009).
104. *Id.* at §§ 9-499.14(A), 11-254.07(A).

of renewable energy facilities.[105] The plan may include: expedited zoning or rezoning procedures; expedited processing of plans, proposals and permits; waivers or abatement of zoning fees, processing fees, improvement district fees, and assessments for development activities; and waiver or abatement of development standards and procedural requirements.[106]

Nevada Assembly Bill 387 requires the Nevada Public Utilities Commission (NV PUC) to designate "renewable energy zones," where "renewable energy resources are sufficient to develop generation capacity" but lack of transmission capacity "constrains the delivery of electricity from those resources to customers."[107] Further, the NV PUC must require utilities to submit a "plan for construction or expansion of transmission facilities to serve renewable energy zones" in connection with the triennial filing required by Nev. Rev. Stat. § 704.741.[108]

In March 2009, the New Mexico Senate passed Senate Memorial 44.[109] The legislation requests the Renewable Energy Transmission Authority (RETA) to "identify and prioritize renewable energy resource zones" within the state that would support competitive renewable energy generation and "identify and prioritize the best viable options for potential transmission corridors to accommodate renewable energy export."[110] In October 2009, the RETA released its report, which provides detailed maps of renewable energy resource zones and recommends future initiatives to eliminate barriers to the development of renewable energy transmission infrastructure.[111] For example, RETA recommends "the establishment of a well-coordinated multi-state effort in the siting and permitting of transmission infrastructure" to eliminate the "multiplicity" of time-consuming state and local regulatory processes.[112]

In December 2009, the New Mexico Public Regulation Commission voted to uphold a hearing officer's decision that third-party renewable energy developers are not "public utilities" subject to regulation under the New Mexico Public Utilities Act.[113] At issue were arrangements in which third-party developers, taking advantage of federal and state tax incentives, finance the installation of renewable energy generation equipment on a customer's premises and then sell the power generated onsite to the customer.[114] The Public Service Company of New Mexico had argued that such arrangements were prohibited as "retail competition in its service territory."[115] New Mexico Governor Bill Richardson praised the decision, saying that it will make the installation of

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105. *Id.* at §§ 9-499.14(B), 11-254.07(D).

106. *Id.*

107. 2009 Nev. Stat. 993.

108. *Id.*

109. S.M. 44, 49th Leg. (N.M. 2009).

110. *Id.*

111. N. M. Renewable Energy Transmission Auth., Response Report to Senate Memorial 44 (2009), *available at* http://www.nmreta.org/new_mexico_reta_documents.php.

112. *Id.* at 40.

113. Press Release, Governor Bill Richardson, Response to PRC's Decision on Renewable Energy Case (Dec. 22, 2009), *available at* http://www.governor.state.nm.us/press/2009/dec/122209_02.pdf.

114. *Id.*

115. Kevin Robinson-Avila, *PNM 'Open' to Legislative Solution of Third-Party Power Agreements*, NEW MEXICO BUSINESS WEEKLY (Jan. 1, 2010).

renewable energy systems more affordable, especially for governmental and nonprofit entities that do not qualify for federal and state incentives.[116]

C. Hydrokinetic Developments

Hydrokinetic energy projects generate electricity from the motion of waves, tides, currents, the flow of inland waterways, or ocean temperature differentials.[117] The hydrokinetic industry is still in its formative stages, with the first hydrokinetic project licensed by the FERC in 2008.[118] Interest in these projects has exploded in the past year, and the FERC has now issued preliminary permits to 139 hydrokinetic projects in twenty-one states,[119] with an additional forty-three preliminary permits currently pending before the Commission.

Critical hydrokinetic legal developments in 2009 included: (1) resolution of disputes over which federal agency has jurisdiction to permit hydrokinetic projects; (2) issuance of final rules by the Department of Interior's Minerals Management Service (MMS) governing offshore renewables located on the Outer Continental Shelf; and (3) preliminary development of ocean zoning laws by several states.

1. FERC Jurisdiction Over Hydrokinetic Projects

Two major regulatory developments in 2009 clarified the FERC's role in licensing hydrokinetic projects. First, the FERC and MMS entered into a Memorandum of Understanding (MOU) that delineated each agency's role in licensing hydrokinetic projects located on the Outer Continental Shelf. Second, the FERC entered into MOUs with several coastal states that delineated federal and state authority over hydrokinetic projects in state territorial waters. These agreements are discussed below.

a. The FERC MOU with the Minerals Management Service Regarding Licensing of Renewable Energy Projects on the Outer Continental Shelf

This year saw the resolution of a jurisdictional dispute between the MMS and the FERC over the regulation of hydrokinetic projects on the Outer Continental Shelf (OCS).[120] Prior to 2009, the FERC and the MMS both

116. Press Release, Governor Bill Richardson, Response to PRC's Decision on Renewable Energy Case (Dec. 22, 2009), *available at* http://www.governor.state.nm.us/press/2009/dec/122209_02.pdf.

117. FERC STAFF WHITE PAPER, LICENSING HYDROKINETIC PILOT PROJECTS 1 (Apr. 14, 2008), *available at* http://www.ferc.gov/industries/hydropower/indus-act/hydrokinetics/pdf/white_paper.pdf.; *See also* OCS Alternate Energy & Alternate Use Programmatic EIS, Ocean Wave Energy, *http://ocsenergy.anl.gov/guide/wave/index.cfm* (last visited Jan. 13, 2009).

118. *City of Hastings, Minnesota*, 125 F.E.R.C. ¶ 61,287 (2008).

119. Alaska, Arizona, Arkansas, California, Delaware, Hawaii, Louisiana, Maine, Massachusetts, Michigan, Missouri, Mississippi, New Hampshire, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Tennessee, Washington, and West Virginia. Additionally, preliminary permits are pending in three additional states, Indiana, Kentucky and Ohio. For a list of pending preliminary permits, visit http://www.ferc.gov/industries/hydropower/indus-act/hydrokinetics/permits-pending.xls.

120. Federal jurisdiction applies to "all submerged lands lying seaward" of state waters, which are limited to the first three miles into the ocean. 43 U.S.C. § 1301(b) (2006). This area is generally known as the OCS. *See also* 43 U.S.C. § 1331(a) (2006) (defining the OCS).

asserted exclusive and conflicting jurisdiction over hydrokinetic projects located on the OCS. The MMS, which traditionally has overseen development of oil and gas projects on the OCS under the Outer Continental Shelf Lands Act (OCSLA), initially asserted exclusive jurisdiction over hydrokinetic projects located on the OCS pursuant to new authority under the EPAct 2005.[121] The FERC, which traditionally has regulated development of hydropower resources under Part I of the FPA, initially asserted exclusive jurisdiction over all hydrokinetic projects pursuant to FPA sections 4(e) and 23(b)(1).[122] For several years, the conflict between the FERC and the MMS resulted in delay and uncertainty for developers of renewable energy project on the OCS.

In 2009, however, the FERC and the MMS entered into a MOU, which resolved the agencies' principal jurisdictional differences.[123] The MOU was executed on April 9, 2009 by FERC Chairman Jon Wellinghoff and Interior Secretary Ken Salazar, and envisions complementary roles for the FERC and the MMS in the regulation of hydrokinetic projects. The MOU established that FERC will issue licenses under the Part I of the FPA[124] and that MMS will issue "leases, easements, and rights-of-way" under the OCSLA[125] for hydrokinetic projects located on the OCS. The FERC and MMS agreed to coordinate "to ensure that hydrokinetic projects meet the public interest", and to cooperate in each other's respective National Environmental Policy Act review obligations.[126]

The MOU establishes the following broad principles, which contemplate coordinated roles for MMS and the FERC in hydrokinetics permitting. (1)The FERC will not issue a license for an OCS hydrokinetic project until the applicant has first obtained a lease, easement, or right-of way from MMS for the site;[127] (2) MMS will include a mandatory condition in all leases, easements, or rights-of-way requiring OCS hydrokinetic applicants to receive a license from FERC prior to construction;[128] (3) The FERC will include any conditions requested by MMS in any FERC license for OCS hydrokinetic projects; and (4) The FERC will not issue preliminary permits for OCS hydrokinetic projects.[129]

121. Section 388 of EPAct 2005 amended the OCSLA by authorizing Interior to grant leases, easements, or rights-of-way on the OCS for the production of energy from sources other than oil and gas. 43 U.S.C. § 1337(p) (2006).

122. In *Pacific Gas & Electric Company*, the Commission for the first time asserted jurisdiction over MMS objection in a licensing proceeding for a group of hydrokinetic pilot projects. The case involved the issuance of preliminary permits for two projects proposed in state and federal waters off the coast of California consisting of approximately 200 wave energy conversion devices to be located half a mile to ten miles offshore, which, in total will generate approximately 80-megawatts. The Interior Department intervened, protesting the Commission's jurisdiction under the Federal Power Act (FPA), arguing that section 388 of the Energy Policy Act of 2005 (EPAct) provides exclusive jurisdiction to the Interior Department to authorize hydrokinetic projects. On rehearing, the Commission issued a lengthy opinion setting forth a legal basis for the Commission's jurisdiction under Part I of the FPA. The Commission relied on a savings clause in section 388 of EPAct to argue that the Commission retained exclusive authority over hydrokinetics on OCS waters.

123. Memorandum of Understanding Between the U.S. Department of the Interior and the Federal Energy Regulatory Commission (Apr. 9, 2009).

124. 16 USC §§ 792-823a (2006).

125. Memorandum of Understanding Between the U.S. Department of the Interior and the Federal Energy Regulatory Commission, at 1 (Apr. 9, 2009).

126. *Id.* at §§ B, D, E.

127. *Id.* at § G.

128. *Id.* at § H.

129. *Id.* at § C.

In agreeing to the MOU, the FERC and the MMS resolved the uncertainty that had previously obstructed development of hydrokinetic projects on the OCS. While questions still remain in the wake of the MOU, the signing of this agreement allowed MMS to finalize its rulemaking governing renewable energy development on the OCS, and allowed for the FERC to move forward with its processes, as discussed below.

In keeping with this new jurisdictional regime, the majority of new preliminary permit applications pending before the FERC pertain to projects located within state territorial waters. Thirty-eight of the fifty-four preliminary permits granted by the FERC in 2009 were for inland waterway projects, while virtually forty of forty-three currently pending applications for preliminary permits are for inland waterway sites. The vast majority of these permit applications are for sites located on either the Mississippi River, or its Ohio River tributary.

b. The FERC Agreements with Maine, Oregon and Washington Regarding Licensing of Renewable Energy Projects in State Territorial Waters

Contemporaneous with executing the MOU with the MMS related to hydrokinetic projects on the federal waters of the OCS, discussed above, the FERC entered into similar framework agreements with Maine, Oregon, and Washington related to hydrokinetic projects in state territorial waters.[130] These largely identical agreements establish that the FERC and the signatory states will, on a case-by-case basis, share relevant information, collaborate on schedules, inform one another as to permitting activities, and generally cooperate in each other's respective permitting activities. Similar to the MOU with the MMS, these agreements further the development of the regulatory process for hydrokinetic projects. Each state MOU recognizes that: (1) the FERC has authority to issue licenses under Part I of the FPA for non-federal wave, tidal, and in-stream energy projects; (2) the signatory states assent to the FERC's pilot project process; (3) the signatory states maintain authority under certain environmental and land use statutes, including the Coastal Zone Management Act and Clean Water Act) applicable to hydrokinetic projects.[131]

130. *See, e.g.*, Memorandum Between the Federal Energy Regulatory Commission and the State of Maine By and Through Its Governor and Departments of Conservation, Environmental Protection, Inland Fisheries and Wildlife, and Marine Resources, State Planning Office, and Governor's Office of Energy Independence and Security (Oct. 8, 2009), *available at* www.ferc.gov/legal/maj-ord-reg/mou/mou/ma.pdf; Memorandum Between the Federal Energy Regulatory Commission and the State of Washington By and Through Its Departments of Ecology, Fish & Wildlife, Natural Resources, Community Trade and Economic Development, and State Parks and Recreation Commission, and the Governor's Office of Regulatory Assistance (Aug. 14, 2009), *available at* www.ferc.gov/legal/maj-ord-reg/mou/mou-wa.pdf; Memorandum Between the Federal Energy Regulatory Commission and the State of Oregon By and Through Its Departments of Fish & Wildlife, Land Conservation and Development, Environmental Quality, State Lands, Water Resources, Parks and Recreation, and Energy (Mar. 26, 2008), *available at* www.ferc.gov/legal/maj-ord-reg/mou/mou-or-final.pdf.

131. *See, e.g.*, MOU Between FERC and Maine, *supra* note 130, §§ A, B, and F.

i. Minerals Management Service Promulgates New Regulations Governing Renewable Power Development on the OCS

On April 29, 2009, the MMS issued its final rule governing renewable development of the OCS (Final Rule).[132] The Final Rule provides that: (i) the MMS will issue leases, easements, and rights-of-way for all renewable projects located on the Outer Continental Shelf; and (ii) the FERC will continue to exercise its FPA hydropower licensing authority governing the construction and operation of hydrokinetic projects.[133] A key distinction is that the MMS's Final Rule will govern all renewable projects located on the OCS including wind, solar, and hydrokinetic; while the FERC will issue licenses only to hydrokinetic projects.

The MMS's Final Rule establishes a competitive regime for leasing portions of the OCS whereby potential developers will bid for an exclusive lease. The process is comparable to the existing process MMS utilizes to issue natural gas drilling leases on the OCS. The competitive process begins when the MMS issues a "call for interest" in the Federal Register when it receives a request to lease a specific site. If the MMS receives no expressions of interest from developers seeking to exploit the same location, then the MMS has the ability to enter into a non-competitive lease or grant with the initial site developer. Otherwise, the MMS will conduct a bidding process to determine which competitor will make the best use of the location.

Entities are allowed to elect either "commercial" or "limited" leases, although the MMS reserves the right to convey sites on the OCS outside of the competitive process for research purposes under a negotiated lease arrangement.[134] The MMS intends to act on limited lease requests within six months, while commercial lease requests are expected to take between one to two years to process.[135]

A commercial lease conveys access and operational rights "necessary to produce, sell and deliver power through spot market transactions or a long term power purchase agreement" over a thirty year period, with the potential for renewal.[136] A commercial lease entitles the lessee to install any necessary cables or pipelines necessary to bring the power or other products to shore.[137]

By contrast, a limited lease allows for site-assessment activities such as installation of a wind monitoring tower or water monitoring, as well as development of new or experimental renewable energy producing technologies. A limited lease may be renewed, but cannot be converted into a commercial lease. While the limited lease provides the same rights of access and easements, it allows only limited sales of power consistent with testing and developing the project and does not permit large-scale commercial operation. Further, a limited lease provides the lessee no preference in applying for a commercial lease at the same site, although a preference provision may be negotiated into the limited

132. Renewable Energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf, 74 Fed. Reg. 19,638 (Apr. 29, 2009) (to be codified at 30 C.F.R. pts. 250, 285, and 290 (2010)).

133. 74 Fed. Reg. at 19,653.

134. 30 C.F.R. 285.238 (2010).

135. Final Rule, 74 Fed. Reg. 19,638, 19,658.

136. *Id.* at 19,647.

137. *Id.*

lease agreement.[138] Overall, however, the MMS regulations indicate a preference for entities engaging in testing activities to apply for a commercial lease, and notes that a lessee may relinquish its lease at any time.[139]

Once a company acquires a lease, it must submit its development plan to the MMS, including plans for the development, construction, operation, and decommissioning of the site. The default lease rate for both commercial and limited leases is three dollars per acre per year, plus an acquisition fee. Commercially viable projects are also required to pay a small percentage of their energy sales to the MMS. Annual rents for rights-of-way or rights-of-use easements across the OCS vary in price, but are generally around five dollars per acre per year.

Critically, the MMS regulations also clarify how a site developer is required to coordinate with the FERC. If the site is a hydrokinetic project, then it remains subject to FERC jurisdiction under Part I of the FPA, and the developer is required to seek a FERC license after it completes the MMS process. No development of the site is permitted until the development plan is approved and the FERC license acquired. In all cases, project developers remain subject to NEPA review, as well as compliance with the Clean Water Act, Coastal Zone Management Act, Endangered Species Act, and Marine Mammals Protection Act.

2. Other Developments in State Territorial Waters-Ocean Zoning

Another development in 2009 included progress in the area of ocean zoning, which is a regulatory tool for implementing a spatial management plan.[140] The federal government[141] and several states, including Massachusetts, Rhode Island, and Virginia, are working on ocean zoning initiatives.[142] These ocean zoning efforts, which strive to balance competing demands for ocean areas between traditional uses such as fishing and recreation with new renewable energy uses, could have a significant impact on the siting of hydrokinetic projects and other ocean-based energy projects by predetermining areas that are open for development. For example, the Massachusetts Ocean Management Plan, which was finalized in December 2009, identifies zones suitable for commercial-scale energy development and establishes certain zones in which any commercial activity is prohibited.[143] The plan establishes three general categories of "Management Areas": (1) Prohibited Areas such as marine sanctuaries in which commercial-scale activities are prohibited; (2) Renewable Energy Areas in which renewable energy projects are expressly contemplated;

138. *Id.* at 19,658.

139. *Id.* at 19,658

140. FARA COURTNEY & JACK WIGGIN, OCEAN ZONING FOR THE GULF OF MAINE: A BACKGROUND PAPER, GULF OF MAINE COUNCIL ON THE MARINE ENVIRONMENT (2003), *available at* www.mass.gov/czm/oceanzoningreport.pdf.

141. *See, e.g.,* INTERAGENCY OCEAN POLICY TASK FORCE REPORT, INTERIM FRAMEWORK FOR EFFECTIVE COASTAL AND MARINE SPATIAL PLANNING (2009), *available at* http://www.whitehouse.gov/administration/eop/ceq/initiatives/oceans/interim-framework.

142. *See, e.g.,* OCEAN SAMP. MGMT. PLAN, RHODE ISLAND OCEAN SPECIAL AREA MANAGEMENT PLAN http://seagrant.gso.uri.edu/oceansamp/ (last visited Mar. 7, 2010).

143. MASSACHUSETTS OCEAN MANAGEMENT PLAN (December 31, 2009), *available at* www.env.state.ma.us/eea/mop/final-v1/v1-text.pdf.

and (3) Multi-Use Areas in which numerous activities are contemplated such as aquaculture, cables and pipelines, extraction of sand and gravel, certain small-scale wind facilities, and wave and tidal facilities. [144]

Although ocean zoning efforts are still in developmental phases in many instances, the Massachusetts Ocean Plan could inform similar zoning initiatives.

D. Developments in Offshore Wind Power[145]

Efforts to develop offshore wind resources intensified in 2009, with the MMS issuing its final rule governing leases and rights-of-way for projects on the OCS. In several parts of the country, local utilities entered into long-term power purchase agreements with offshore wind developers. This year also saw substantial political support for wind farms off of the Mid-Atlantic region. The governors of Delaware, Maryland, New Jersey, and Virginia filed comments at the FERC urging reforms to spur investment in off-shore wind resources,[146] and also entered into a MOU to promote development of offshore wind resources.[147]

1. MMS Offshore Wind Activities

On April 29, 2009, the MMS issued its Final Rule governing the leasing of portions of the OCS for renewable energy development.[148] This Final Rule replaced the MMS's interim policy, which authorized developers to install offshore data collection and technology testing facilities in Federal waters, but did not permit full-scale commercial development (Interim Policy).[149] The MMS issued four leases in November, 2009 under the Interim Policy to: Deepwater Wind off the shore of Rhode Island; Fisherman's Energy Center of New Jersey; and two to NRG Bluewater Wind for projects off of New Jersey and Delaware. These leases confer no priority rights to subsequently develop the OCS, but do provide the companies the right to deploy test projects.[150]

Additionally, the MMS has moved to finalize its environmental analysis of the Cape Wind project.[151] The proposal consists of 130, 3.6 megawatt wind turbine generators covering twenty-four square miles of Nantucket Sound in Massachusetts. The project would have a capacity of about 468 MW. The MMS assumed responsibility for permitting the Cape Wind project after the passage of EPAct 2005, and published the Cape Wind draft EIS in January 2008

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144. *Id*. at 2-1 - 2-9.

145. Abraham Silverman, one of the authors of this section, is employed by NRG Energy, Inc., which in 2009 acquired Bluewater Wind.

146. *See, e.g., Comments of the Governors of Delaware, Maryland, Virginia and New Jersey Under AD09-8-000*, Docket AD09-8-000 (Nov. 25, 2009).

147. Memorandum of Understanding Between The States of Delaware and Maryland and the Commonwealth of Virginia Related to Common Interests Associated with Offshore Wind Energy Development (Nov. 9, 2009), *available at* www.env.state.ma.us/eea/mop/final-v1/v1-text.pdf.

148. Renewable Energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf, 74 Fed. Reg. 19,638 (Apr. 29, 2009) (to be codified at 30 C.F.R. pts. 250, 285, and 290 (2010)).

149. 72 Fed. Reg. 62,673 (Nov. 6, 2007).

150. *Id.* at 62,674.

151. *See, e.g.*, Lease Application of Cape Wind Associates, L.L.C., http://www.mms.gov/offshore/RenewableEnergy/CapeWind.htm (last visited Mar. 7, 2010).

and the final EIS on January 16, 2009.[152] In connection with MMS's NEPA analysis of the Cape Wind application, the National Park Service designated Nantucket Sound as eligible to be listed on the National Register of Historic Places as a traditional cultural property on November 19, 2009.[153] On January 10, 2010, the Secretary of the Interior announced that he intended to conduct a "final review" of whether to issue the Cape Wind project a lease, and to issue a final decision by April, 2010.[154]

2. Power Purchase Agreements for Offshore Wind

In 2009, two new power purchase agreements (PPA) were awarded to offshore wind developers by state agencies and utilities.

a. Deepwater Wind (Rhode Island)

On December 9, 2009, National Grid USA and Deepwater Wind announced a twenty-year power purchase agreement for the output of the 28.8-MW Block Island Deepwater Wind project in Rhode Island. The announcement stated that the project will sell energy at a cost of 24.4 cents per kWh, escalated at 3.5% per year for the life of the PPA. Deepwater's project consists of eight 3.6 MW wind turbines at an estimated cost of between $160 million and $200 million. The project is designed to test the feasibility of constructing a larger wind farm with 100 turbines and a capacity of 385 MW at a cost of $1.3 billion. If Deepwater Wind stays on schedule, it expects to be the first offshore U.S. wind farm in operation in 2013.

b. Bluewater Wind

On December 8, 2009, Bluewater was awarded a fifty-five MW PPA by the State of Maryland, which will be supplied off of Bluewater's 450 MW planned wind farm located fourteen miles off the coast of Bethany Beach, Delaware. This is addition to the 200 MW PPA NRG Bluewater received from Delmarva Power & Light in 2008, that was approved by the State of Delaware on September 2, 2008.[155] The NRG Bluewater project in Delaware will include approximately 153 MW turbines and is scheduled to reach commercial operation in late 2013. NRG Energy, Inc. acquired Bluewater Wind for a reported $10 million on November 9, 2009 from a consortium led by Babcock and Brown.[156]

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152. *See, e.g.*, CAPE WIND ENERGY WIND PROJECT FEIS (Jan. 2009), *available at* http://www.mms.gov/offshore/AlternativeEnergy/PDFs/FEIS/Cape%20Wind%20Energy%20Project%20FEIS.pdf.

153. NATIONAL PARK SERVICE, DETERMINATION OF ELIGIBILITY NOTIFICATION (Jan. 4, 2010), *available at* http://www.nps.gov/history/nr/publications/guidance/NantucketSoundDOE.pdf.

154. *See, e.g.*, Press Release, Department of the Interior, Secretary Salazar Initiates Final Review of Cape Wind Proposal (Jan. 4, 2010), *available at* http://www.mms.gov/ooc/press/2010/press0105.htm.

155. *See* PSC Order No. 7440, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Supply Service by Delmarva Power & Light Company Under Del. C. §1007(c) & (d): Review and Approval of the Request for Proposals for the Construction of New Generation Resources Under 26 Del. C. §1007(d) (Sept. 2, 2008), *available at* http://depsc.delaware.gov/orders/7440.pdf.

156. Steve Gelsi, *NRG Energy Sees Offshore Wind Revenue by 2014*, MARKET WATCH (Nov. 13, 2009), *available at* http://www.marketwatch.com/story/nrg-energy-eyes-offshore-wind-revenue-by-2014-2009-11-10.

3. Ontario's Feed-In Tariff for Offshore Wind

On October 1, 2009, Ontario enacted the first feed-in tariff for offshore wind farms providing power to the province, administered by the Ontario Power Authority.[157] The tariff would provide offshore wind developers nineteen cents per kW-hour (Canadian) and is scheduled to remain in place for twenty years. Ontario also removed its moratorium on wind projects on the Canadian side of the Great Lakes in 2008, which has prompted a number of large wind developers to announce projects on the Canadian side of the Great Lakes.[158]

II. DEMAND-SIDE MANAGEMENT AND SMART GRID

A. Federal Government Activity

1. Pending and Enacted Federal Legislation

As noted above,[159] on February 17, 2009 President Obama signed the ARRA, a package of spending and tax measures intended to stimulate the economy and create or save jobs.[160] The ARRA provided $787 billion in direct government spending or tax cuts: of that amount, about $65 billion was directed to various energy-related initiatives, including programs to boost energy efficiency and develop and install Smart Grid technologies.

With regard to energy efficiency, a total of $6.3 billion was provided for block grants to state and local governments to help them fund various energy efficiency and energy conservation programs. Of this amount, $3.2 billion was provided for block grants to states, units of local government, and tribal governments under a program originally created by the Energy Independence and Security Act of 2007 (EISA).[161] This program was created to support state, local, and tribal efforts to implement strategies that reduce fossil fuel emissions, reduce the total energy use of the entity receiving the grant, and improve energy efficiency in the transportation, building, and other sectors.[162]

The other $3.1 billion in state and local block grant funds included in the ARRA was directed to fund certain state energy programs previously authorized in the Energy Policy and Conservation Act of 1975.[163] Under that statute, states that adopt energy conservation plans meeting certain guidelines may receive financial assistance from the federal government to assist in implementing such plans.[164] Importantly, however, the ARRA placed conditions on the ability of

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157. For further background on Ontario's feed-in tariff, *see* ONTARIO POWER AUTHORITY, RENEWABLE ENERGY FEED-IN TARIFF PROGRAM (Jan. 17, 2008) http://fit.powerauthority.on.ca/Page.asp?PageID=1226&SiteNodeID=1058&BL_ExpandID=260 (last visited Mar. 7, 2010); ONTARIO POWER AUTHORITY, ONTARIO UNVEILS NORTH AMERICAN'S FIRST FEED IN TARIFF (Mar. 12, 2009), *available at* http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6858.

158. Press Release, Ontario Ministry of Natural Resources (Jan. 17, 2008), *available at* http://www.mnr.gov.on.ca/en/Newsroom/LatestNews/MNR_E004126.html.

159. American Recovery and Reinvestment Act of 2009 (ARRA), Pub. L. No. 111-5, § 123, 123 Stat. 115 (2009).

160. *Id*.

161. 123 Stat. at 138.

162. EISA § 542, 42 U.S.C. § 17152 (2006).

163. 123 Stat. at 138.

164. 42 U.S.C. § 6323 (2006).

states to receive a block grant from this $3.1 billion appropriation. Specifically, a state may only receive funding if it notifies the Secretary of Energy that it has met three conditions: (1) the appropriate state regulatory agency has or will adopt utility rate policies that "ensure[] that utility financial incentives are aligned with helping their customers use energy more efficiently" and provide utilities with timely cost recovery and earning opportunities associated with cost-effective, measurable and verifiable energy savings; (2) the state and any local units of government have adopted updated residential and commercial building codes, and adopted a plan to achieve ninety percent compliance with those codes in new buildings and retrofits within eight years; and (3) the state will prioritize the use of the grants to target existing energy efficiency programs operated by the state or utilities.[165]

As noted above,[166] proposed energy and climate legislation advanced in Congress during 2009. Those measures included, as discussed above, proposed national combined renewable energy and energy efficiency resource standards.[167] Additionally, S. 1462 (approved by the Senate Energy and Natural Resources Committee on July 16, 2009) includes a "national electric system efficiency and peak demand reduction goal."[168] This provision would establish a national policy goal to improve the load factor of electric systems by 1.5% per year during each of the years between 2010 and 2030.[169] The DOE, the FERC, RTO/ISOs, and the National Association of Regulatory and Utility Commissioners would be directed to develop a national action plan to meet or exceed this national goal. Additionally, the DOE would be required to establish a public website to provide information on the progress of states and load-serving entities in meet the national efficiency goals.

2. FERC Actions

a. Rehearing and Implementation of Order No. 719 Demand Response Regulations

In 2008, the FERC issued Order No. 719, which amended the FERC's regulations to require RTO/ISOs to adopt reforms to their tariffs and rules to satisfy new regulations in four subject areas: (1) demand response, including market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of RTOs and ISOs to their customers and other stakeholders.[170] During 2009, the FERC issued Order No. 719-A, addressing requests for rehearing of Order No. 719.[171] For the most part, the FERC affirmed its determinations and rejected the requests for rehearing. With regard to its demand response requirements, however, the Commission made a significant change to the regulations adopted in Order No.

165. ARRA § 410, 123 Stat. at 146-47.

166. American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009); American Clean Energy and Leadership Act of 2009, S. 1462, 111th Cong. (2009).

167. *Id.*

168. American Clean Energy and Leadership Act of 2009, S. 1462, 111th Cong. (2009).

169. *Id.* at § 295(b).

170. S*ee, e.g., Report of the Renewable Energy and Demand-Side Management Committee*, 30 ENERGY L. J. 273, 296-97 (2009) (for a full discussion of Order No. 719).

171. 74 Fed. Reg. 37,776 (Jul. 29, 2009).

719 that required RTO/ISOs to allow entities to aggregate the demand of retail customers and bid that demand directly into the RTO/ISOs markets, unless the laws or regulations of the relevant electric retail regulatory authority (usually a state commission) would not permit retail customers to participate directly in the wholesale market.[172] To address concerns that smaller utilities (particularly municipal or cooperative utilities) might find the aggregation of their retail customers burdensome, or may not be able to obtain an explicit ruling from their relevant regulatory authority (such as a city council) preventing such aggregation, the Commission adopted different procedures for utilities distributing less than 4 million MWh per year. For these utilities, retail customers may be aggregated to provide demand response directly into RTO/ISO markets only where the relevant regulatory authority explicitly allows such aggregation.

Later in 2009, the Commission issued several orders ruling on filings made by certain RTO/ISOs to comply with the regulations adopted in Order No. 719.[173] With regard to one of the areas of focus in that rulemaking, the responsiveness of RTO/ISOs to their customers and stakeholders, the Commission declined to rule on the RTO/ISO's plans for compliance. Instead, the Commission announced that it would hold a Technical Conference on February 4, 2010, "to provide a forum for participants to discuss . . . the responsiveness of regional transmission organizations (RTOs) and independent system operators (ISOs) to their customers and other stakeholders."[174]

i. National Assessment of Demand Response Potential

In June 2009, the FERC issued it "National Assessment of Demand Response Potential," as required by Section 529(a) of the EISA.[175] This report provides an estimate of demand response potential – nationally, regionally, and on a state-by-state basis - for residential and other types of electric customers, and analyzes the effect of using technologies, such as programmable thermostats, to assist consumers. The report found that the potential for peak electricity demand reductions nationwide is between 38 GW and 188 GW (up to 20T of national peak demand), depending on the extent to which demand response measures are applied. Additionally, the report offered a set of recommendations for overcoming barriers to demand response.[176]

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172. *Id.* at 37, 778-84.

173. *Ca Indep. Sys. Operator Corp*., 129 F.E.R.C. ¶ 61,157 (2009); *Southwest Power Pool, Inc*., 129 F.E.R.C. ¶ 61,163 (2009); *N.Y. Indep. Sys. Operator, Inc*., 129 F.E.R.C. ¶ 61,164 (2009); *PJM Interconnection*, 129 F.E.R.C. ¶ 61,250 (2009).

174. First Notice of Technical Conf., 74 Fed. Reg. 59,975 (Nov. 19, 2009).

175. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007).

176. FERC, A NATIONAL ASSESSMENT OF DEMAND RESPONSE POTENTIAL (June 2009), *available at* http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

ii. National Action Plan on Demand Response

The FERC also took steps in 2009 to implement the directive in section 529 of the EISA to develop a "National Action Plan on Demand Response."[177] In October, FERC Staff issued a discussion draft containing possible elements of this plan.[178] The discussion draft focused on the three sets of strategies and activities outlined in the EISA: (1) providing technical assistance to States; (2) developing a national communications program, to communicate the benefits of demand response to the public; and (3) developing tools and materials to support demand response. At the end of November, the FERC held a two-day technical conference to review and solicit input on the discussion draft, and heard testimony from state regulators, utility representatives, and large consumers, among others.

b. Smart Grid Policy Statement

The FERC issued an important policy statement during 2009 that provides initial guidance with respect to the development of Smart Grid technology.[179] This policy statement identifies key priority areas for the development of Smart Grid interoperability standards, which may be filed with the FERC under section 1305(d) of the EISA.[180] The FERC discussed two cross-cutting issues, system security and inter-system communication, and four key priority areas: (1) wide-area situational awareness; (2) demand response; (3) electric storage; and (4) electric transportation. The FERC reasoned that developing standards in these areas would provide a foundation for the development of other standards.

The policy statement also included an interim rate policy intended to allow entities to recover the cost of investments they make in Smart Grid technology in their FERC-jurisdictional rates. The rate policy requires applicants to make four demonstrations: (1) the smart grid facilities in question will advance the policies and goals in section 1301 of the EISA, (2) the smart grid facilities will not adversely affect the reliability and cyber security of the bulk-power system, (3) the applicant has minimized the possibility of stranded investment in smart grid equipment, and (4) the applicant agrees to share certain information on its project through the Department of Energy Smart Grid Clearinghouse.[181] In December, the FERC issued its first order applying this policy statement.[182] In that order, the FERC granted a request from Pacific Gas and Electric to recover in its transmission rates the costs of a synchrophasor project being developed in conjunction with other entities in its region. The Commission also granted a request that the company be permitted to seek recovery of 100% of its

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177. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1665 (2007).

178. FERC, POSSIBLE ELEMENTS OF A NATIONAL ACTION PLAN ON DEMAND RESPONSE – A DISCUSSION DRAFT (Oct. 28, 2009), *available at* http://www.ferc.gov/EventCalendar/Files/20091028124306-AD09-10-000-Discussion.pdf.

179. *Smart Grid Policy, Final Rule*, 128 F.E.R.C. ¶ 61,060 (2009), 74 Fed. Reg. 37,098 (July 27, 2009).

180. Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1665 (2007).

181. *Smart Grid Policy*, 128 F.E.R.C. ¶ 61,060 (2009).

182. *Pacific Gas & Elec. Co.*, 129 F.E.R.C. ¶ 61,251 (2009).

abandoned plant costs in the event that the project is abandoned for reasons beyond its control.

B. State Activity

1. Northeast

In the Northeast, Connecticut and Rhode Island each enacted legislation in 2009 requiring that efficiency standards be incorporated into state building projects. In Connecticut, Public Act No. 09-192, effective July 8, 2009, requires the State Building Code to be amended to incorporate the 2012 International Energy Conservation Code.[183] Public Act 09-192 also requires the State Building Code be revised, on or after July 1, 2010, to include construction standards relating to indoor air quality and water conservation, lighting and electrical systems of buildings over a certain size, referencing nationally accepted green building rating systems, such as Leadership in Energy and Environmental Design (LEED), the National Green Building Standard, or equivalent.[184] The act also increases the Department of Public Safety Codes and Standards Committee from seventeen members to eighteen members, with one member required to have expertise in energy efficiency matters.[185] Rhode Island's legislation, enacted in November 2009, requires public building construction and renovation projects over a certain size (new facilities in excess of 5,000 square feet and all renovations in excess of 10,000 square feet) be designed and built to achieve LEED or equivalent certification.[186]

The Vermont Energy Act of 2009 directed the Vermont Department of Public Service (VT DPS) to develop a self-managed energy efficiency pilot program for eligible transmission and industrial electric ratepayers.[187] Under the program proposed by the VT DPS in August 2009, eligible customers would receive a credit toward the Energy Efficiency Charge assessed by their utility if they commit to making certain qualifying expenditures toward electric or fuel efficiency projects.[188] The Vermont Public Service Board is required to review the VT DPS's proposed program and enact a program based on that proposal by December 31, 2009.[189]

2. Mid-Atlantic

The Governor of Virginia signed an executive order, "Greening of State Government" in June 2009[190] as part of the greater "Renew Virginia" Initiative. This Order builds upon the executive order "Energy Efficiency in State Government," and sets out to reduce non-renewable energy purchases and increase overall energy savings. In addition to requiring that new buildings

183. 2009 Conn. Acts 09-192 (Reg. Sess.).

184. *Id.*

185. *Id.*

186. An Act Relating to Public Property and Works – Establishing a Green Buildings Act, 2009 R.I. Pub. Laws 212.

187. The Vermont Energy Act, 2009 Vt. Laws 45.

188. Vt. Pub. Service Board, *Self-Managed Efficiency Program* (Aug. 31, 2009), *available at* http://psb.vermont.gov/sites/psb/files/projects/EEU/SMEEP/8-31-09_DPS_SMEEP_Proposal.pdf.

189. 2009 Vt. Laws 45.

190. Va. Exec. Order No. 82 (2009).

(greater than 5,000 square feet) and major renovations (where the cost is greater than fifty percent of building value) be built to LEED Silver or Green Globes Two Globes Standards, agencies and institutions are instructed to purchase or lease Energy Star-rated appliances and equipment, if Energy Star is available for the category of equipment/appliance.[191] In addition, the order instructs the Commonwealth to encourage the private sector to adopt energy-efficient building standards by giving preference when leasing facilities for state use to facilities meeting LEED Silver or Green Globes Two Globes standards.[192]

3. Southwest

In January 2010, the Arizona Corporation Commission issued a notice of proposed rulemaking on electric energy efficiency standards.[193] The purpose of the proposed rules is "for affected utilities to achieve energy savings through cost-effective energy efficiency programs in order to ensure reliable electric service at reasonable rates and costs."[194] The proposed rules would require large electric utilities to achieve cumulative annual energy savings (measured in kWh) beginning in 2011.[195] By 2020, an affected utility's cumulative annual energy savings must be equivalent to at least twenty-two percent of its retail electric energy sales for the prior calendar year.[196]

191. *Id.*; Va. Exec. Order No. 48 (2009).

192. *Id.*; Va. Exec. Order No. 82 (2009).

193. Notice of Proposed Rulemaking on Elec. Energy Efficiency, 16 Ariz. Admin. Reg. 90-99 (Jan. 15, 2010).

194. *Id.* at 91.

195. *Id.* at 94 (Proposed Rule R14-2-2404).

196. *Id.*

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